UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units: Advanced Notice of Proposed Rulemaking	))))))	**Docket No. EPA–HQ–OAR–2017–0545** *Via Regulations.gov* *February 26, 2018*

Comments of Sierra Club, the Center for Biological Diversity, and Earthjustice

On behalf of our millions of members and supporters, Sierra Club, the Center for Biological Diversity, and Earthjustice ("Joint Commenters") submit these comments on Environmental Protection Agency ("EPA") Administrator Scott Pruitt's Advanced Notice of Proposed Rulemaking ("ANPRM") regarding emission guidelines for greenhouse gas emissions from existing electric utility generating units ("EGUs") under section 111(d) of the Clean Air Act, 42 U.S.C. § 7411(d). 82 Fed. Reg. 61,507 (Dec. 28, 2017). This ANPRM was issued in close coordination with the Administrator's proposal to repeal the Clean Power Plan ("CPP"), the agency's section 111(d) carbon dioxide ("CO_2") emission guidelines for existing fossil fuel-fired power plants. 80 Fed. Reg. 64,662 (Oct. 23, 2015) (final CPP rule); 82 Fed. Reg. 48,035 (Oct. 16, 2017) (proposed CPP repeal). Joint Commenters strongly oppose this repeal proposal; as we will explain in coalition comments submitted in that docket, the proposal is unlawful for a host of reasons and should be summarily withdrawn. In particular, the Administrator's new legal premise underlying the ANPRM is incorrect: the Clean Air Act's statutory language, context, and legislative history all belie Administrator Pruitt's newfound (and extremely cramped) assertion that the best system of emission reduction ("BSER") for a section 111(d) rule covering power plant CO_2 emissions must only include "measures . . . based on a physical or operational change to a building, structure, facility, or installation at that source, rather than measures that the source's owner or operator *can implement on behalf of* the source at another location." 82 Fed. Reg. at 61,512 (emphasis in original). As we will discuss in our coalition comments on the CPP repeal, even if the Administrator's new theory were correct—and it is not—CPP would still be lawful, since its BSER consists of "emission reduction measures that can be *applied to or at* a stationary source." *Id.* (emphasis in original).

In the alternative, without waiving any of our objections to the Administrator's CPP repeal proposal or his rationale for issuing the ANPRM, if the agency were to finalize the repeal proposal, EPA can and must develop a robust and protective section 111(d) emission guideline based on this new statutory interpretation. Notably, such an approach must not consist entirely (or even primarily) of efficiency (i.e., heat-rate) improvements ("HRI") at individual coal-fired EGUs;[1] a program of this nature would not meet EPA's legal obligation to adopt a rule that achieves the maximum CO_2 emission reductions feasible. Even a 10 percent improvement in heat rates at existing coal-fired plants is nowhere near the greatest

[1] Throughout these comments, we frequently refer to "coal-fired EGUs" or some variation thereof. This category should also be understood to include oil- and gas-fired steam EGUs except in our discussion of fuel pretreatment and selection at coal plants. Thus, to the extent that we discuss heat rate improvements and reduced utilization as the BSER for coal-fired units, those same techniques (again, not including fuel pretreatment and selection) would apply to oil and gas steam EGUs, which EPA must include along with coal-fired units for the purposes of establishing an emission guideline document. Natural gas combustion turbines, on the other hand, would be covered in a separate sub-category, as discussed in Section III.B.

reductions that are feasible, and would be wholly insufficient. Further, because on-site efficiency improvement opportunities at existing gas-fired units,[2] including at natural gas combined cycle units ("NGCCs"), will most likely be very small, an HRI-only standard would not meaningfully control CO_2 emissions from this subcategory of EGUs.

While HRI at regulated sources should be *one* component of an emission reduction program for power plants, it cannot be the *only* component. If EPA were to adopt the "on-site only" approach described in the CPP repeal proposal and ANPRM, the majority of emission limits in this sector must be achieved by a basic and fundamental on-site measure: reduced utilization of each individual coal-, gas-, and oil-fired EGU. The option of simply operating less is a quintessentially inside-the-fenceline means of reducing emissions from these units. In addition, it is by far the simplest and most cost-effective method available to achieve the necessary emission reductions from this sector, as shown by the record supporting the CPP's Building Blocks 2 and 3. Under the approach we discuss in these comments, EPA's emission guideline would include two mandatory emission limits for each regulated source: a unit-specific emission rate (expressed in lbs CO_2/MWh) and annual plant-by-plant emission limit (expressed in tons of CO_2 per calendar year or in lbs CO_2/hr on a rolling annual average basis), with a BSER based on (1) HRI at regulated fossil units, achieved through improved operation and maintenance practices and equipment upgrades, (2) fuel pretreatment and selection for coal-fired units (i.e., coal-drying, blending, and beneficiation), and, most importantly, (3) reduced utilization of regulated fossil units. Each plant's ton-per-year emission limit would be determined by a combination of the plant's age and efficiency with older and less efficient plants expected to operate less frequently and thus emit less. EPA should also consider a unit's impact on overburdened communities when determining its reduced utilization target.

Under the approach we discuss in these comments, the guideline's emission limitations would be unit-specific. At the same time, section 111(a)(1) of the Clean Air Act requires EPA to "tak[e] into account . . . energy requirements" when selecting the BSER. 42 U.S.C. § 7411(a)(1). Accordingly, EPA must consider grid-wide impacts when issuing a CO_2 emission guideline for power plants. To that end, under the program discussed here, EPA would calculate the amount of reduced utilization to expect at regulated fossil units in each balancing area[3] based on electricity demand and growth/decline projections for the area, the characteristics of the existing fossil units, announced and likely retirements of such units, and the availability of renewable energy and efficiency measures to make up for lost generation from regulated fossil plants. EPA would also provide for further reductions in coal units' utilization based on the availability of underutilized NGCC capacity. This program would not employ a credit program for efforts by fossil-fired EGUs to invest in or procure increased generation from renewable resources. Rather, the total availability of new generation from renewable energy and efficiency resources would determine by *how much* affected fossil units would reduce their utilization.

The CPP rulemaking record provides a useful set of analyses for determining the level of emission reductions at fossil fuel-fired plants that can be achieved in each state in consideration of grid reliability.

[2] All references to "gas-fired units" or some variation thereof throughout these comments mean gas-fired combustion turbines (including simple cycle or combined cycle units), as opposed to natural gas-fired steam EGUs. As discussed in n. 1, *supra*, gas- and oil-fired steam EGUs would be regulated in the same manner as coal-fired steam EGUs except for the fuel pretreatment and selection component of the BSER, which applies only to coal units.

[3] A balancing area is a geographic region in which the electricity supply and demand is monitored and accounted for by a grid operator, such as an independent system operator ("ISO") or a state regulator in areas without ISOs.

In developing any new program, EPA should begin with its earlier electric sector analyses from the CPP rulemaking record, making important updates, refinements, and corrections to those analyses and the data they relied upon. The ANPRM notes that "there have been significant changes in the power sector since the CPP was finalized" in 2015, 82 Fed. Reg. at 61,513, and even more changes have occurred since 2012, the CPP's baseline year. The continued retirement of both coal- and gas-fired units, ongoing progress in energy efficiency savings, and the dramatic plummet in the costs of renewable energy demonstrate that greater emission reductions can be achieved under a new program than were expected under the CPP, and the new rulemaking must reflect these changes.

To calculate the guideline's mandatory emission reduction targets, EPA would first evaluate the HRI and fuel pretreatment/selection measures that can be implemented on a plant-specific basis and determine an adjusted baseline emission rate for each regulated unit. This adjusted baseline emission rate would represent the first mandatory component of the guideline, and states would translate these emission rates into enforceable performance standards for each regulated unit within their borders.

EPA would then determine the degree of fossil unit curtailment that is feasible in each balancing authority (i.e., in each ISO) based on the availability of replacement generation primarily from renewable resources and energy efficiency. To allocate these ISO-wide curtailment targets among the individual units, EPA would account for a combination of each unit's age and efficiency, apportioning a greater share of the emission reductions to older and/or less-efficient units. EPA should also consider an approach that would assume greater curtailment expectations for units that emit air pollution that harms overburdened communities. Using the unit-by-unit curtailment targets, EPA would calculate an adjusted baseline generation figure for each EGU. Finally, EPA would multiply each unit's adjusted baseline emission rate by its adjusted baseline generation to produce the second enforceable component: each unit's annual emission limit in tons CO_2/year (or, alternatively, lbs CO_2/hr on a rolling annual average basis). For each regulated unit within their borders, states would translate these annual emission limits into enforceable performance standards in their plans. States could directly translate EPA's tons-per-year ("TPY") limits into performance standards without making changes; or they could allocate plants' TPY emission reduction obligations differently at the outset of the program, so long as the overall emission reductions are at least as great and key environmental justice principles are observed.

These comments provide a roadmap for a reduced utilization model that EPA must consider if it initiates a rulemaking to propose revised section 111(d) emission guidelines for existing fossil fuel-fired EGUs. We first briefly discuss the acute urgency of climate change and address new research published since the Clean Power Plan that reiterates and strengthens EPA's conclusion that power plant CO_2 emissions pose a grave and growing threat to public health and welfare. We then describe the legal principles in the Clean Air Act that underscore our policy recommendations. Next, we provide the details for a potential emission guideline based on HRI, fuel pretreatment and selection at coal plants, and reduced utilization, describing program design elements and target calculation exercises, as well as a number of other technical and data-related issues. Lastly, we address specific questions on which EPA solicited comment in the ANPRM.

I. Recent Studies Overwhelmingly Confirm EPA's Findings that Climate Change Threatens Catastrophic Harm and Is Already Causing Devastating Impacts.

In the CPP rulemaking, EPA reaffirmed its 2009 finding, based on an already voluminous scientific record, that greenhouse gases drive ever more dangerous climate change and endanger public health and welfare.[4] EPA also summarized the key findings of major peer-reviewed studies issued after 2009, including the U.S. Global Change Research Program ("USGCRP"),[5] the Intergovernmental Panel on Climate Change ("IPCC"),[6] and the National Research Council ("NRC")[7] confirming this conclusion. Based on this overwhelming evidence, EPA determined that climate change "has become the nation's most important environmental problem," and that mitigation is now an urgent necessity.[8] EPA found that "[w]e are now at a critical juncture to take meaningful action to curb the growth in CO_2 emissions and forestall the impending consequences of prior inaction."[9] Scientific literature issued since 2015 only bolsters EPA's findings. Joint Commenters will submit a more detailed description of that literature to the docket for the proposed CPP repeal, but a summary is provided here.

The data are plain: climate change is happening, and is increasingly severe. Temperature increases have been particularly alarming; eleven of the twelve hottest years on record since 1880 have occurred since

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[4] 80 Fed. Reg. at 64,682-88.

[5] USGCRP, Melillo, Jerry M., *et al.,* "Climate Change Impacts in the United States: The Third National Climate Assessment," (2014), http://nca2014.globalchange.gov/ (hereafter, "USGCRP 2017").

[6] IPCC, "Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects," Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, Field, C.B., *et al.,* (2014), www.ipcc.ch/report/ar5/wg2/. IPCC, "*Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation*," Special Report of Working Groups I and II of the Intergovernmental Panel on Climate Change, Field, C.B., *et. al.,* (2012), https://wg1.ipcc.ch/srex/.

[7] NRC, "Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean," Committee on the Development of an Integrated Science Strategy for Ocean Acidification Monitoring, Research, and Impacts Assessment (2010), www.nap.edu/catalog/12904/ocean-acidification-a-national-strategy-to-meet-the-challenges-of. NRC, "Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia," Committee on Stabilization Targets for Atmospheric Greenhouse Gas Concentrations (2011), www.nap.edu/catalog/12877/climate-stabilization-targets-emissions-concentrations-and-impacts-over-decades-to. NRC, "National Security Implications of Climate Change for U.S. Naval Forces," Committee on National Security Implications of Climate Change for U.S. Naval Forces (2011), www.nap.edu/catalog/12914/national-security-implications-of-climate-change-for-us-naval-forces. NRC, "Understanding Earth's Deep Past: Lessons for Our Climate Future," Committee on the Importance of Deep-Time Geologic Records for Understanding Climate Change Impacts (2011), www.nap.edu/catalog/13111/understanding-earths-deep-past-lessons-for-our-climate-future. NRC, "Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future," Committee on Sea Level Rise in California, Oregon, and Washington (2012), www.nap.edu/catalog/13389/sea-level-rise-for-the-coasts-of-california-oregon-and-washington. NRC, "Climate and Social Stress: Implications for Security Analysis," Committee on Assessing the Impacts of Climate Change on Social and Political Stresses (2013), www.nap.edu/catalog/14682/climate-and-social-stress-implications-for-security-analysis. NRC, "Abrupt Impacts of Climate Change: Anticipating Surprises," Committee on Understanding and Monitoring Abrupt Climate Change and Its Impacts (2013), www.nap.edu/catalog/18373/abrupt-impacts-of-climate-change-anticipating-surprises.

[8] 80 Fed. Reg. at 64,774; *see also* EPA, Basis for Denial of Petitions to Reconsider and Petitions to Stay the CAA section 111(d) Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units, 1 (Jan. 11, 2017) (noting that climate change is the nation's "most urgent and important environmental challenge").

[9] 80 Fed. Reg. at 64,774.

2003.[10] 2017 was the third warmest year ever recorded for the U.S., with only 2012 and 2016 warmer than last year.[11] U.S. annual average temperatures have increased by 1.8°F (1.0°C) since 1901,[12] with the number of heat waves (defined as six-day periods with a maximum temperature above the 90th percentile for 1961 through 1990) rising since the 1960s.[13] Extreme weather has become more frequent and more devastating, with torrential rainfall and floods on the increase.[14] Studies have attributed climate change as a factor that made the record rainfall totals from both Hurricane Harvey[15] and the 2016 flood in south Louisiana[16] more likely and intense. Sea level rise is accelerating, and will make coastal floods more frequent and severe during storms.[17] For example, relative sea levels in New York City increased 19.7 inches (50 centimeters) between 1800 and 2000.[18] Predictions of sea level rise continue to surge upward: as EPA noted in the CPP rulemaking, "projected future rates of sea level rise . . . are 40 percent larger to more than twice as large as the previous estimates from [2007]."[19] The rise in sea levels also increased the height of flooding during Hurricane Sandy from 7.5 to 9.2 feet (2.3 to 2.8 meters).[20] Both droughts and widespread wildfires are increasing and becoming more devastating, causing loss of life and widespread damage in the West.[21] CO_2 emissions have also made the surface of

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[10] NOAA, National Centers for Environmental Information, *State of the Climate: Global Climate Report for Annual 2016* (2017), www.ncdc.noaa.gov/sotc/global/201613, (last visited Nov. 29, 2017).
[11] NOAA, National Centers for Environmental Information, *2017 Was the 3rd Warmest Year on Record for U.S.* (2018), http://www.noaa.gov/news/2017-was-3rd-warmest-year-on-record-for-us (last visited Jan. 10, 2018).
[12] USGCRP 2017 at 13.
[13] *Id.* at 191.
[14] *Id.* at 20.
[15] Emanuel, K., "Assessing the Present and Future Probability of Hurricane Harvey's Rainfall 2017," PNAS Early Edition (2017), www.pnas.org/cgi/doi/10.1073/pnas.1716222114. Risser, M.D. and M.F. Wehner, "Attributable Human-induced Changes in the Likelihood and Magnitude of the Observed Extreme Precipitation During Hurricane Harvey," Geophys. Res. Lett. In Press, doi: 10.1002/2017GL075888. van Oldenborgh, G.J., et al., "Attribution of Extreme Rainfall from Hurricane Harvey, August 2017," 12 Environ. Res. Lett. 124009 (2017), https://doi.org/10.1088/1748-9326/aa9ef2.
[16] van der Wiel, K., et al., "Rapid Attribution of the August 2016 Flood-inducing Extreme Precipitation in South Louisiana to Climate Change 2016," 21 Hydrol. Earth Syst. Sci. 897 (2017), www.hydrol-earth-syst-sci.net/21/897/2017/.
[17] USGCRP 2017 at 27.
[18] Lin, N., et al., "Hurricane Sandy's Flood Frequency Increasing from Year 1800 to 2100," 113 PNAS 12071 (2016), www.pnas.org/content/113/43/12071. We converted the return period in Lin et al. 2016 to probabilities with National Weather Service, "Flood Return Period Calculator," www.weather.gov/epz/wxcalc_floodperiod (accessed Nov. 28, 2017).
[19] 80 Fed. Reg. at 64,684.
[20] Lin, et al., 2016.
[21] USGCRP 2017 *Id.* at 231.

global oceans about 30 percent more acidic over the last 150 years, [22] and acidification is now higher than at any time in at least the last 66 million years.[23]

Recent studies solidify and expand upon EPA's finding in the CPP rulemaking that these and other effects of climate change and ocean acidification are negatively affecting human health, particularly that of children, the elderly, low-income communities, and indigenous populations.[24] A recent review found that extreme heat leads to deadly organ failure, including such pathologies as ischemia (inadequate blood supply), heat cytotoxicity, and inflammatory response, conditions that, in the context of heat waves, can affect the brain, heart, intestines, kidneys, and liver.[25] The United States will very likely see thousands to tens of thousands more premature heat-related deaths in the summer under business as usual.[26] Climate change will also worsen air quality by accelerating the formation of ground-level ozone pollution, increasing fine particulate and ozone emissions from wildfires, and making pollen and mold allergy seasons longer and more severe.[27]

Similarly, the effects of climate change and ocean acidification harm biodiversity, ecosystem services, and public lands. EPA's findings from the CPP rulemaking on these harms[28] are buttressed by more recent studies. For example, one report estimates that 4.3°C of additional global warming caused by continued high levels of greenhouse gases could lead to the extinction of one in six of the world's species,[29] while other recent reports document current losses to shallow coral reefs[30] and oyster farms in the U.S[31] due to climate change. In addition, U.S. national parks are overwhelmingly at the extreme warm end of historical temperatures and are experiencing major threats to their flora and fauna. For

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[22] USGCRP 2017 at 372. Acidification is causing many parts of the ocean to be undersaturated with the calcium carbonate minerals that are the building blocks for the skeletons and shells of many marine organisms, which impairs these organisms' ability to produce and maintain their skeletons and shells. *See* Pacific Marine Environmental Laboratory, National Oceanic and Atmospheric Administration, What Is Ocean Acidification, https://www.pmel.noaa.gov/co2/story/What+is+Ocean+Acidification%3F (last visited Feb. 26, 2018).
[23] USGCRP 2017 at 364.
[24] EPA*, Regulatory Impact Analysis for the Clean Power Plan Final Rule*, 4-2 – 4-3, 7-16 – 7-20. (Aug. 2015).
[25] Mora, C., et al., "Twenty-Seven Ways a Heat Wave Can Kill You: Deadly Heat in the Era of Climate Change," 10 Circ Cardiovasc Qual Outcome e004233 (2017), *available at* http://circoutcomes.ahajournals.org/content/10/11/e004233.
[26] USGCRP at 44.
[27] *Id.* at 70.
[28] *E.g.,* 80 Fed. Reg. at 64,684.
[29] Urban, M.C., "Accelerating Extinction Risk from Climate Change," 348 Science 571 (2015), *available at* http://science.sciencemag.org/content/sci/348/6234/571.full.pdf.
[30] EPA, "Multi-Model Framework for Quantitative Sectoral Impacts Analysis: A Technical Report for the Fourth National Climate Assessment,"EPA 430-R-17-001, 171 (2017) (hereafter, "Sectoral Impacts Analysis"), *available at* https://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=335095.
[31] Lemasson, A.J., et al., "Linking the Biological Impacts of Ocean Acidification on Oysters to Changes in Ecosystem Services: A Review," 492 J. Exp. Mar. Biol. Ecol. 49 (2017), *available at* www.sciencedirect.com/science/article/pii/S002209811730059X?via%3Dihub.

example, rising sea levels in Florida's Everglades National Park threaten the mangrove ecosystem that filters saltwater, thereby preserving freshwater wetlands.[32]

The ever-increasing devastation wrought by climate change is already disrupting key parts of the U.S. economy as well, impacts that will only increase in the coming years and decades. According to a 2017 technical assessment by EPA's Climate Change Impacts and Risk Analysis project, climate change will cost the U.S. economy *hundreds of billions of dollars each year under conservative estimates*.[33] These cost estimates include, among other things, labor losses of $160 billion per year,[34] $140 billion in heat-related deaths,[35] and $120 billion in damages to coastal property[36] per year by 2090.

Crucially, delays in achieving emission reductions exponentially increase the risk of harm and mean that much more expensive steps will be required later to mitigate the damage caused by today's emissions. Because CO_2 is long-lived in the atmosphere, each year's emissions add to the accumulated total already in the atmosphere, building year after year to ever higher concentrations.[37] In 2014, the White House issued a report demonstrating that the cost of further delay is not only steep but also potentially irreversible, rising exponentially as delay continues.[38] Based on conservative assumptions (omitting, for example, the effects of tipping points), and without taking account of the accelerating harm done since its publication, the report values the cost of *delay alone* at no less than $150 billion (or 0.9 percent of global output) for every year of delayed action if the delay results in an increase of temperatures over pre-industrial levels by just one additional degree Celsius above a threshold of 2°C.[39] Every incremental degree of warming thereafter will sharply increase aggregate economic damages. For example, an additional degree of warming above a 3°C increase (which is already far too high to avoid the worst effects of climate change) would depress global output by another 1.2 percent.[40] These costs are not one-time, but are incurred permanently and cumulatively, year after year.[41]

[32] National Park Service, "Climate Change – Everglades National Park" https://www.nps.gov/ever/learn/nature/cceffectssalineglades.htm (last visited Feb. 26, 2018).
[33] Sectoral Impacts Analysis at 209–10.
[34] *Id.* at 54.
[35] *Id.* at 42.
[36] *Id.* at 4.
[37] 80 Fed. Reg. at 64,517 (citation omitted). "According to the National Research Council, 'Emissions of CO_2 from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because CO_2 in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.'"
[38] The White House, *Cost of Delaying Action to Stem Climate Change,* 2 (July 29, 2014), *available at* https://obamawhitehouse.archives.gov/blog/2014/07/29/new-report-cost-delaying-action-stem-climate-change.
[39] *Id.* at 4-5, citing the DICE model (Nordhaus (2013)).
[40] *Id.*
[41] *Id.* at 2.

Although many climate change effects, such as a certain degree of sea level rise, are already committed (or "baked in"),[42] the IPCC's Fifth Assessment Report and other expert assessments have established global carbon budgets to avoid even greater harm still. These budgets correspond to the total amount of CO_2 that can be released into the atmosphere while maintaining some probability of staying below a given temperature target and thus avoiding some of the worst effects of climate change. According to the IPCC, the cumulative anthropogenic emissions of CO_2 must remain below about 1,000 gigatonnes ("$GtCO_2$") from 2011 onward for a 66 percent probability of limiting warming to 2°C above pre-industrial levels, and to 400 $GtCO_2$ from 2011 onward for a 66 percent probability of limiting warming to 1.5°C.[43] These carbon budgets have been reduced to 850 $GtCO_2$ and 240 $GtCO_2$, respectively, from 2015 onward.[44] Since global CO_2 emissions in 2015 alone totaled 36 $GtCO_2$,[45] humanity is rapidly consuming the remaining carbon budget. Power plants are the U.S.' largest stationary source of greenhouse gas emissions; in light of the extremely limited carbon budget still available, no CO_2 emission reduction strategy can succeed without curbing these sources' emissions to the maximum extent feasible.

Astonishingly, the ANPRM confronts neither the overwhelming evidence of climate change's devastating impacts nor the existential urgency of the threat. In fact, apart from one reference to the title of an NRDC report that discusses heat rate improvements at power plants, the word "climate" appears nowhere in the ANPRM. Administrator Pruitt's omission of the very reason why power plant CO_2 regulations are essential, and his utter disregard of the enormous benefits power plant emission reductions will produce, shows how his approach—proposing to repeal the CPP without a replacement rule in place and issuing an ANPRM focused on heat rate improvements only—is unlawful and arbitrary. By contrast, the regulatory approach we describe in these comments represents a robust program for reducing climate-disrupting CO_2 pollution from the single largest stationary source of those emissions in the country.

II. Legal Principles

A. EPA Must Issue Emission Guidelines that Reduce Power Plant CO_2 Pollution to the Maximum Extent that is "Achievable," "Adequately Demonstrated," and "Not Exorbitantly Costly."

Two fundamental principles must guide EPA's rulemaking efforts: (1) the Clean Air Act obligates EPA to issue section 111(d) emission guidelines to curb harmful CO_2 pollution from existing fossil fuel-fired EGUs, and (2) the quantity of emission reductions achieved under those guidelines must be the maximum amount feasible. With regard to the first principle, section 111(d) requires EPA to establish emission guidelines covering "any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source." 42 U.S.C. §

[42] Mengel, Matthias *et al., "*Committed Sea-Level Rise under the Paris Agreement and the Legacy of Delayed Mitigation Action,"DOI:10.1038/s41467-018-02985-8, Nature Communications 9:601 (Feb. 20, 2018), *available at* https://www.nature.com/articles/s41467-018-02985-8.

[43] IPCC, "Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change," R.K. Pachauri and L.A. Meyer, eds., 63–64 and Table 2.2 (2014).

[44] Rogelj, Joeri et al., "Differences between Carbon Budget Estimates Unraveled," 6 Nature Climate Change 245, Table 2 (2016).

[45] *See* Le Quéré, Corrine, et al., "Global Carbon Budget 2016," 8 Earth Syst. Sci. Data 605 (2016), *available at* www.globalcarbonproject.org/carbonbudget/16/data.htm.

7411(d)(1). In 2015, EPA promulgated the Carbon Pollution Standards, which apply to new, modified, and reconstructed fossil fuel-fired EGUs. Accordingly, the agency *must* issue CO_2 emission guidelines covering existing sources within that same category; any gap between a hypothetical CPP rescission and the issuance of new emission guidelines would leave EPA in default of its legal duty under section 111(d). To the extent that the ANPRM leaves open the possibility that EPA may choose *not* to regulate CO_2 emissions from existing power plants, the plain language of section 111(d) slams the door shut on that possibility.

Indeed, EPA must control CO_2 pollution from the entire sector of fossil fuel-fired power plants. In 1971, EPA listed fossil steam EGUs as a source category that "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare," 42 U.S.C. § 7411(b), and listed stationary combustion turbines in 1977. 36 Fed. Reg. 5,931 (March 31, 1971); 42 Fed. Reg. 53,657 (Oct. 3, 1977). These listings alone require the agency to regulate air pollution from those power plants under section 111. In *Massachusetts v. EPA*, the Supreme Court held that greenhouse gases—including CO_2-- "fit well within the Clean Air Act's capacious definition of an 'air pollutant'" and that EPA must regulate such emissions if it determined that they endanger public health and welfare. 549 U.S. 497, 532 (2007). Two years later, the agency indeed determined, based on "a large body of robust and compelling scientific evidence," 82 Fed. Reg. at 64,682, that anthropogenic greenhouse gas emissions are the primary driver of climate change and thus seriously endanger public health and welfare. 74 Fed. Reg. 66,496 (Dec. 15, 2009). The D.C. Circuit upheld the Endangerment Finding in its entirety against an industry challenge, and the Supreme Court refused to review that holding. *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 116-25 (D.C. Cir. 2012), *rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014); *see also Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 418, 187 L. Ed. 2d 278 (2013) (granting certiorari only on a narrow issue that did not encompass EPA's Endangerment Finding).

As discussed in Section I, the scientific evidence supporting EPA's 2009 Endangerment Finding has only grown stronger in the intervening eight years. Furthermore, fossil fuel-fired power plants are by far the largest stationary source of CO_2 pollution in the United States, contributing 35 percent of all energy-related[46] domestic CO_2 emissions in 2016.[47] Given the grave harm posed by CO_2 emissions, the huge quantities of CO_2 released by fossil fuel-fired EGUs, and the readily available means of reducing these emissions without undermining electricity reliability, EPA simply has no choice under the law: it *must* regulate CO_2 emissions from both new and existing power plants under section 111. *See* also Order, *West Virginia v. EPA*, 15-1363, ECF No. 1687838, at 2 (Aug. 8, 2017) (Cir. Judges Tatel and Millett, concurring) (recognizing that the Endangerment Finding "triggered an affirmative statutory obligation to regulate greenhouse gases"); *see also Am. Elec. Power v. Connecticut*, 564 U.S. 410, 424 (2011) (section 111 "speaks directly" to the regulation of climate pollution from existing power plants).

Furthermore, the agency cannot issue regulations that achieve merely nominal or marginal emission reductions from this sector; it must cut power plant CO_2 pollution as much as feasible. In *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981), the court held that "we can think of no sensible interpretation

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[46] U.S. Energy Info. Admin., *Monthly Energy Review*, 181, 187 (Jan. 2018), *available at* www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

[47] In recent years, fossil fuel combustion for energy purposes has accounted for between 93 and 94 percent of the total U.S. CO_2 emissions. *See* EPA*, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015*, Table ES-2 (Apr. 2017), *available at* https://www.epa.gov/sites/production/files/2017-02/documents/2017_complete_report.pdf.

of the statutory words 'best technological system'[48] which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions." The court also rejected an argument that "'EPA may not consider total air emissions in deciding on a proper NSPS'" with the assertion that "this position [is] untenable given that one of the agreed upon legislative purposes . . . *requires* that the standards must maximize the potential for long term economic growth 'by reducing emissions *as much as practicable*.'" *Id.* (emphasis added); *see also* 42 U.S.C. § 7401(b) (the Clean Air Act's fundamental purpose is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population."[49]); Summary of the Provisions of Conference Agreement on Clean Air Act Amendments of 1970, 116 Cong. Rec. 42,384 (Dec. 18, 1970) (sources regulated under section 111 "must be controlled to the maximum practicable degree regardless of location").

This principle is exemplified by *State of New York v. Reilly*, 969 F.2d 1147, 1153 (D.C. Cir. 1992). In that case, the court rejected EPA's decision not to ban the combustion of lead-acid vehicle batteries in its performance standards for municipal waste combustors ("MWCs"). EPA had admitted that the combustion of these batteries was "a significant source of lead in MWC emissions," and that "a ban [on their combustion] would achieve air benefit[s]," but nonetheless selected a more lenient standard that did not prohibit this practice. *Id.* Because the agency had not properly justified its decision to adopt the weaker standard, the court remanded the rule to the agency as unlawful. *Id.* Analogously, in *NRDC v. EPA*, the Second Circuit struck down EPA's technology-based effluent limits ("TBELs") under the Clean Water Act for ballast water discharges from ships. 808 F.3d 556, 571-72 (2d Cir. 2015). The court held that EPA's TBELs, which were required to incorporate the "best available technology economically achievable" ("BAT"), were unlawful because the agency had not considered alternative systems that were both available and more protective than the one that EPA had selected as BAT. *Id.*

In short, section 111(d) emission guidelines must reduce air pollution to the maximum feasible degree within the parameters of what is achievable, adequately demonstrated, and not exorbitantly costly. *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999). This is particularly true with regard to CO_2 emissions from existing power plants. The United States is second only to China as the world's leading emitter of greenhouse gases, and fossil fuel-fired power plants remain the country's largest stationary source of greenhouse gas pollution. The Administrator's adoption of an existing source rule that did not reduce emission power plant CO_2 emissions to the maximum feasible extent would violate section 111—as well as the Administrative Procedure Act, which requires agencies to "offer a rational connection between the facts found and the choice made*," Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 52 (1983). Any rule that did not achieve deep cuts in climate-disrupting CO_2 emissions from the nation's largest stationary source of this pollution would run directly contrary to the agency's factual determinations in the Endangerment Finding, as well as abundant evidence in the CPP record, these comments, and other sources known and available to EPA. It would thus be arbitrary and capricious.

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[48] In 1977, Congress amended section 111 to require new source standards reflecting "the best technological system of continuous emission reduction" and existing source standards reflecting the "best system of continuous emission reduction." Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 685, 699-700. In 1990, Congress restored the original "best system of emission reduction" for both new and existing source standards. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(a), 104 Stat. 2399, 2631.

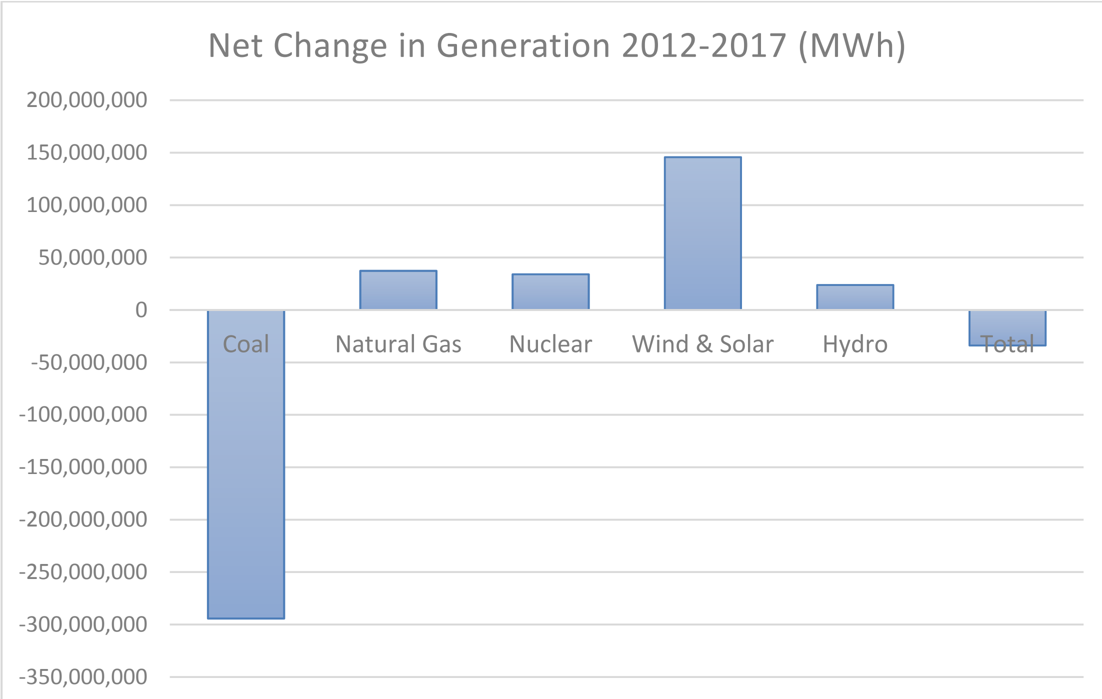
[49] Three additional purposes are itemized, all of which aim to achieve "the prevention and control of air pollution." 42 U.S.C. § 7401(b).

Unfortunately, the ANPRM suggests that, if the Administrator issues a replacement rule at all, it will be based solely on HRI at fossil fuel-fired power plants (and perhaps HRI at coal plants only). This approach would be woefully inadequate. In Section III.A.iv.a, we provide a quantitative analysis of several options EPA could adopt and find that, under all circumstances, an HRI-only approach would achieve only a tiny fraction of the emission reductions that would occur either under the CPP or under business-as-usual *without* the CPP. Under a worst-case scenario, an HRI-only policy would achieve effectively zero emission reductions—or even emission *increases*. Quite simply, an HRI-only program would represent a dereliction of EPA's obligations under the Clean Air Act and would therefore be unlawful.

If the Administrator insists on eliminating the CPP, the agency must provide not a *weaker* rule, but a new and updated program that achieves much *greater* cuts in CO_2 pollution. The maximum quantity of emission reductions that is feasible is not static, but must take into account new facts and circumstances. As the Supreme Court observed in *Massachusetts*, when addressing problems like climate change, agencies should "refin[e] their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed." *Id.* Since the CPP was finalized in 2015—and even more since the CPP's baseline year of 2012—circumstances in the electric sector have, indeed, changed considerably. According to the Energy Information Administration ("EIA"), as of November 2017, coal generation over the previous 12 months was 10 percent below 2015 levels and 19 percent below 2012 levels.[50] On the other hand, renewable generation grew dramatically during this time frame; 12-month wind power totals in November 2017 were 24 percent above 2015 levels and 56 percent above 2012 levels.[51] The growth in solar energy was even more impressive, expanding by 109 percent relative to 2015 and over 1,100 percent relative to 2012.[52] All the while, gas generation remained largely stable: in November 2017, 12-month generation figures for natural gas were 5 percent below 2015 levels and 3 percent above 2012 numbers.[53] The chart below reflects these changes in the electric sector.

[50] EIA, *Electric Power Monthly*, Table 1.1 (Nov. 2017), https://www.eia.gov/electricity/monthly/ (last visited Feb. 23, 2018).
[51] *Id.*
[52] *Id.*
[53] *Id.*

Chart No. 1 – Net Change in U.S. Electricity Generation by Source 2012-2017[54]



The data are stark; fossil fuel-fired generation has declined since the CPP was issued while renewable generation has soared. Market conditions are ripe for a rule that achieves much deeper emission cuts than those contemplated under the CPP. EPA must capitalize on recent movements in the electric sector to address climate change much more aggressively than it ever has before.

B. Reduced Utilization of Fossil Fuel-Fired Power Plants is a Lawful and Appropriate Element of BSER

For the emission reduction program discussed in these comments, the primary component of the BSER is reduced utilization of fossil fuel-fired power plants. This measure is entirely appropriate under section 111 and can be implemented entirely on-site at regulated sources: operating a power plant less requires nothing other than the controls that exist in the plant's operating room. Indeed, this method has already achieved substantial emission reductions in the recent past and reflects continuing trends in the power sector. According to EIA, electric sector CO_2 emissions from coal-fired power plants reached their peak in 2007, totaling 1,987 million metric tons for the year. A decade later, in 2016, annual emissions from electric sector coal plants had fallen to 1,241 million metric tons, an impressive decline of 37.5 percent.[55] However, during that same decade, the coal fleet's CO_2 emission rate actually *increased* by 1.5 percent, from 2,192 lbs/MWh in 2007 to 2,225 lbs/MWh in 2016.[56] *The entire quantity of the fleet's emission reductions between 2007 and 2016 occurred because coal units reduced their utilization* (including many units that reduced operations down to zero by retiring). The EIA statistics bear this out: in 2007, the nation's coal fleet generated just under 2 billion MWh of electricity, while in 2016, it

[54] *Id.*
[55] EIA, *Monthly Energy Review*, 187 (Jan. 2018), www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.
[56] *Id.* at 111, 187.

generated approximately 1.23 billion MWh, a 38.5 percent reduction that closely mirrors coal units' overall reduction in CO_2.[57]

Given the predominant (and, in fact, unassisted) role that reduced utilization has played in curbing electric sector emissions in recent years, it would violate the Clean Air Act (including the requirement for maximum feasible emission reductions) and would be arbitrary and capricious *not* to include this measure as a major component of the BSER for any inside-the-fenceline program. EPA itself determined in the CPP that reduced utilization is a highly effective means of reducing CO_2 from power plants. *See, e.g.*, 80 Fed. Reg. at 64,732, 64,753, 64,779-82.In fact, the generation-shifting in Building Blocks 2 and 3 relied on reduced utilization and would have achieved substantial emission reductions under the expectation that fossil fuel-fired power plants would run less frequently. Yet an approach like the one suggested in the ANRPM, which would incorporate *no* form of reduced utilization, would leave an overwhelming portion of available emission reductions unrealized, as discussed in Section III.A.iv.a below. This would violate the Clean Air Act's requirements and would be arbitrary and capricious.

The language of the statute confirms that reduced utilization is a lawful element of a BSER determination under section 111. As defined by section 111(a)(1), a "standard of performance" is "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[58] 42 U.S.C. § 7411(a)(1). This provision enumerates several limitations on the BSER: it cannot include measures that are not achievable or not adequately demonstrated, for example, and it must reflect consideration of costs, energy requirements, and non-air health and environmental impacts. Nowhere, however, does the statutory text indicate that the BSER must also be limited to measures that permit units to operate at the same capacity they did prior to regulation. While industry and its advocates claim otherwise, such a constraint appears nowhere in the statute. *Cf. Hercules Inc. v. EPA*, 938 F.2d 276, 280-81 (D.C. Cir. 1991) (rejecting EPA interpretation that "reads into the statute a drastic limitation that nowhere appears in the words Congress chose and that, in fact, directly contradicts the unrestricted character of those words . . . EPA has literally rewritten the statute by inserting words of limitation that Congress never drafted.").

The definition in section 111(a)(1) links the BSER to an "emission limitation." The term "emission limitation" (along with "emissions standards") is, in turn, defined in section 302(k) as "a requirement established by the State or the Administrator which *limits the quantity, rate, or concentration* of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operational standard promulgated under this chapter." *Id.* § 7602(k) (emphasis added). The argument advanced by some parties that a standard of performance must reflect "fewer emissions" relative to "the same product" describes one particular kind of emission rate: a quantity of pollution

[57] *Id.* at 111.
[58] While it is up to the states, rather than EPA, to establish standards of performance that are enforceable against individual existing sources, 42 U.S.C. 7411(d)(1), those standards must reflect the BSER. Both section 111(a)(1) and EPA's regulations task EPA, not the states, with establishing the BSER. 40 C.F.R. § 60.22.

emitted relative to a fixed unit of industrial output.[59] Indeed, the approach described in these comments would require each source to achieve a unit-specific, output-based emission rate reflecting HRI and fuel pretreatment and selection of coal.

However, the term “emission limitation” also encompasses other kinds of emission rates, such as pollution per unit of input or pollution per unit of time. The statutory language authorizes these kinds of rates in section 111 rules; indeed, EPA has implemented them in the past. For example, the new source performance standards for fossil fuel-fired steam EGUs, as well as those for industrial, commercial, and institutional steam generating units, include SO_2 standards that use heat input (expressed in MMBtu) as the denominator. 40 C.F.R. §§ 60.42c, 60.43Da. For pneumatic controllers in the oil and gas sector, EPA has issued section 111 performance standards that limit methane and VOC emissions to 6 standard cubic feet per hour (except for sources located at gas processing plants, which must have a bleed rate of zero). *Id.* § 60.5390a. The Clean Air Act authorizes EPA to issue input- or temporally-based emission rates for fossil fuel-fired EGUs.

Even if the word “rate” as it appears in section 302(k) were limited to output-based rates only—and it is not— EPA would still be authorized to issue emission limits for power plants based on tons of CO_2 per year: section 302(k) also authorizes emission limits based on “quantit[ies].” 42 U.S.C. § 7602(k). A tons/year limit is a “rate ” within the meaning of section 302(k), but even if it were not, it is a “quantity” within the plain meaning of the statute. An understanding of section 111 that did not permit tons/year limits in section 111 regulations would effectively read the word “quantity” out of the statute. This would violate the “cardinal principle of statutory construction” that “a statute ought, upon the whole, to be so construed that, if it can be prevented, no clause, sentence, or word shall be superfluous, void, or insignificant.” *TRW Inc. v. Andrews*, 534 U.S. 19, 31 (2001). Such an interpretation would also place on the word “rate” a limitation that Congress did not include. *Cf. Hercules Inc. v. EPA*, 938 F.2d at 280-81. The language of the statute reveals that Congress intended to afford EPA a broad array of choices in formulating section 111 regulations, and this array includes limits expressed in tons/year of CO_2 emissions from power plants.

The legislative history of the Clean Air Act confirms that the statute authorizes the approach we discuss in these comments. In his summary of the conference report on the 1970 Clean Air Act Amendments, bill sponsor Senator Edmund Muskie described section 112’s hazardous air pollutants program as requiring “emission standards . . . [that] provide an adequate margin of safety to protect the public health.” Summary of the Provisions of Conference Agreement on Clean Air Act Amendments of 1970, 116 Cong. Rec. 42,384 (Dec. 18, 1970). Senator Muskie explained that “[t]his could mean, effectively, that a plant would be required to close because of the absence of control techniques. It could include emission standards which called for no measureable emissions.” *Id.* Sections 111 and 112 both require emission standards that are achievable, that take into account cost, and that address non-air quality health and environmental impacts and energy requirements. Senator Muskie’s remarks confirm that the Clean Air Act authorizes emission standards that result in or are premised on reduced operations—or even retirement— of certain regulated sources. Of course, the statute’s limiting factors may, in some circumstances, place upper bounds on the *amount* of reduced utilization that emission guidelines or

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[59] “Output” in this context refers to the product that the regulated entity creates. For power plants, output is electricity, measured in terms of megawatt-hours (“MWh”). “Input” refers to that which is entered into the regulated source in order to create output. For fossil fuel-fired power plants, input is the heat content of the fuel burned in the unit, measured in terms of millions of British thermal units (“MMBtu”).

standards can provide for. The program we describe in these comments fully accounts for those constraints and is tailored accordingly. *See* Section III.A.iv.b.

In other Clean Air Act contexts, Congress has also acknowledged reduced utilization as an often appropriate and advantageous means of reducing emissions, particularly from fossil fuel-fired power plants. In the CPP, EPA affirmed that "[b]oth Congress and the EPA have recognized reduced generation as one of the measures that fossil fuel-fired EGUs may implement to reduce their emissions of air pollutants and thereby achieve emission limits."80 Fed. Reg. at 64,780. For example, in designing Title IV's acid rain trading program for coal-fired power plants, Congress anticipated that sources would meet their SO_2 and NO_x emission reduction obligations through reduced utilization. *See id.* Hence, section 408(c)(1)(B) includes specific requirements for EGUs that choose to satisfy their SO_2 and NO_x emission targets "by reducing utilization of the unit as compared with its baseline or by shutting down the unit." *See id.* (citing 42 U.S.C. § 7651g(c)(1)(B)).

EPA has also endorsed reduced utilization in the context of Clean Air Act programs that are more explicitly "technological." For example, the Regional Haze Program is premised on application of the "best available retrofit technology," or BART, for certain sources that contribute to impaired visibility in national parks. 42 U.S.C. § 7491(b)(2)(A). By regulation, BART is defined as "an emission limitation based on the degree of reduction achievable through the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility." 40 C.F.R. § 51.301. In establishing BART-based limitations for covered sources, permitting authorities have frequently set (and EPA has approved) pollution limits based on a combination of technological approaches *and* limits on capacity factors. *See, e.g.,* 82 Fed. Reg. 15,139, 15,140 (March 27, 2017) (approving Arizona's revised Regional Haze SIP, which established BART-based pollution limits for the Cholla Power Plant reflecting, among other things, "an annual average capacity factor of less than or equal to 20 percent"); 77 Fed. Reg. 24794, 24,809-10 (Apr. 25, 2012) (setting BART-based NO_x limits of 383 and 665 tons per year, respectively, for Units 5 and 6 of New York's Oswego Harbor Power, reflecting annual capacity factors of 5 percent and 10 percent); 77 Fed. Reg. 51,915, 51,916 (August 28, 2012) (approving New York's revised BART determinations for Oswego Harbor Power Units 5 and 6).

In fact, in 2014, EPA approved Oklahoma's BART revision for Northeastern Power Station, which mandated that "the facility will shut down one of the subject units (either Unit 3 or Unit 4) no later than April 16, 2016," and that "the facility will incrementally decrease capacity utilization for the remaining unit between 2021 and 2026, culminating with the complete shutdown of the remaining unit no later than December 31, 2026." 79 Fed. Reg. 12,944, 12,945 (March 7, 2014). *See also* 40 C.F.R. Part 51, Appendix Y- Guidelines for BART Determinations Under the Regional Haze Rule at IV.D.4.d.2 ("When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, *then you must make these parameters or assumptions into enforceable limitations*.") (emphasis added). If curtailed generation and unit retirements are appropriate elements of a best available retrofit technology determination, then reduced utilization is surely a proper element of section 111's best system of emission reduction as well.

Similarly, reduced utilization has directly figured into best available control technology ("BACT") determinations for new fossil fuel-fired power plants under the New Source Review ("NSR") program. In 2010, the Wisconsin Department of Natural Resources issued an NSR permit to the Rockgen Energy Center natural gas-fired power plant that required each of the turbine processes to operate no more than 3,800 hours in any 12 consecutive months, while also limiting the number of hours that these turbines fired with distillate fuel.[60] More recently, in 2014, EPA Region 6 issued an NSR permit for the Antelope Elk Energy Center, also a gas-fired EGU, that limited the turbine to 4,572 operational hours on a 12-month rolling basis.[61] Air permits frequently rely on limits for both annual emissions and hours of operation to achieve pollution reduction.

The statute's language, state and federal regulatory history, and the statements of the Clean Air Act's framers all make clear that reduced utilization is a lawful element of the BSER where warranted by the particular facts of the source category and the regulated pollutant. Given the substantial emission curtailments at coal-fired power plants that have already occurred in the last decade because of reduced utilization, the opportunity for large additional reductions in the future, and the surge in available renewable generation and energy efficiency measures at plummeting costs, this measure is a *necessary* element of the BSER for any emission guidelines that would replace or update the CPP. Furthermore, as we discuss in Section III.B, reduced utilization of gas-fired power plants must also play a substantial role in reducing emissions from these sources.

III. EPA Can Design a Program that Adheres to its New Statutory Interpretation and Achieves Large Emission Reductions Through a Combination of Heat-Rate Improvements, Fuel Pretreatment and Selection of Coal, and Reduced Utilization of Fossil Fuel-Fired EGUs.

As we will discuss more fully in comments to be submitted on Administrator Pruitt's proposed CPP repeal, the premise underlying the agency's ANPRM—that section 111 guidelines must consist of a BSER based entirely on on-site measures—is unlawful and arbitrary. Nor is the Administrator correct in asserting that the CPP would be unlawful even under his unreasonably cramped legal theory. However, if the Administrator were nevertheless to eliminate the CPP, the agency must design a program that would achieve large CO_2 emission reductions from fossil fuel-fired EGUs. In this section, we describe how EPA can design such a program, with a BSER based on heat-rate improvements, fuel pretreatment and selection of coal, and reduced utilization of fossil-fired units.

A. Defining an Appropriately Protective BSER and Emission Guidelines for Existing EGUs

In the ANPRM, EPA has solicited comments "identifying the BSER that can be implemented at the level of an affected source, including aspects related to efficiency (heat rate) improvement technologies and practices as well as other systems of emission reduction" under its revised legal theory. 82 Fed. Reg. at 61,510. A strongly protective BSER for existing fossil fuel-fired EGUs would encompass four elements. The first three measures would be (1) emission reductions achieved through changes in operation and maintenance ("O&M") practices at each regulated facility to improve its heat rate; (2) emission reductions achieved through technological improvements at each facility to further improve its heat rate, and (3) emission reductions achieved through coal-drying, mixing, and beneficiation at each coal-fired unit. Based on these three measures, EPA would derive a source-specific, lbs CO_2/MWh emission limit for each unit that states would translate into enforceable performance standards in their plans.

However, these three elements alone could not constitute the BSER. They would produce insufficient emission reductions to satisfy the Clean Air Act's requirements and address the urgency of climate

[60] Title V Renewal Permit for Rockgen Energy Center, LLC, Permit No. 113308030-P10, Condition I.C.1(1) at p. 29 of 55 (Wis. Dept. Nat. Res., 2/4/2010).

[61] PSD Permit for Antelope Elk Energy Center, Permit No. PSD-TX-1358-GHG, Condition III.A.2.d at p. 7 of 14 (EPA Region 6, 6/2/2014).

change. Furthermore, the rate reductions (in lbs CO_2/MWh) that these measures would achieve could easily be offset by small increases in generation at regulated units. Accordingly, EPA can only fulfill its legal obligation to ensure the greatest emission reductions feasible through an additional fourth element of the BSER: reduced utilization (i.e., curtailed generation) at each individual regulated EGU. As discussed below, EPA's emission guideline would apply the fourth BSER component to each regulated unit's mandatory lbs CO_2/MWh emission rate to derive a second enforceable emission limit, expressed as the maximum tons of CO_2 that the source could emit in a given compliance year (i.e., the unit's "TPY limit"). Alternatively, this limit could expressed in lbs CO_2/hr on a rolling annual average basis. Under this approach, each unit remains responsible for complying with its lbs CO_2/MWh and TPY limits entirely through reductions in its end-of-stack emissions; it would not include a mechanism for affected sources to acquire or exchange credits or allowances from or with other entities. For more discussion on credits/allowances, *see* Section III.C below.

i. Emission reductions achieved through improved O&M practices at each coal-fired unit.

It is well demonstrated that coal-fired power plants can reduce their CO_2 emissions by improving their heat rates—that is, the efficiency with which they convert the heat content in fuel into electrical energy. Heat rate improvements, or HRI, can be achieved at coal units through a combination of operational and maintenance practices and technology upgrades. Because there are many measures and upgrades that could improve power plants' HRIs, and because the fleet of existing EGUs is extremely varied in terms of the measures and upgrades already implemented, our program establishes a unit-by-unit approach based on each source's past performance. Under this approach, the average improvement in heat rate would exceed 6 percent per source.

Evidence shows that the existing coal fleet is not operating at the maximum level of efficiency that is feasible; certain operating and maintenance practices that are now common, such as part-load operation, frequent soot-blowing, and other such activities, can increase a coal-fired unit's CO_2/MWh emission rate by 10 percent or more. This was the conclusion of Sierra Club's 52-Unit Study, an analysis included in its 2014 comments on the CPP proposal and referenced by EPA in the ANPRM.[62]

While the 52-Unit Study does not establish the full range of emission reductions that are achievable through improved O&M practices, it does reflect a reasonable "floor" representing the minimum improvements that can be achieved at each facility. The study reveals that, on average, existing coal-fired units can be expected to reduce their CO_2 emissions by approximately 6 percent merely by maintaining their 95th percentile rolling annual average CO_2/MWh emission rate.[63] The study also shows that the historic long-term variation in performance is itself highly variable, with some units' rolling annual emission rates varying by less than 2 percent and others' varying by more than 15 percent.[64] The significant variation in long-term emission rates between one facility and the next indicates that each unit's specific operation and maintenance practices (as opposed to inherent and hence uncontrollable factors) correlates with its emission rate at any given time. Units that have not adhered to the best O&M practices can thus improve their heat rates—and lower their emissions—by adopting such practices.

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[62] *See* Sierra Club and Earthjustice, *Comments on EPA's Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602-27986, 38–46 and attachments (Dec. 1, 2014).

[63] *Id.*

[64] *Id.* at 40–42.

In the CPP rulemaking, EPA evaluated the potential heat rate improvements of existing coal-fired EGUs by analyzing the heat input and gross electricity output rate data from 2002 to 2012 for 884 coal-fired EGUs.[65] The agency grouped the EGUs by the three regional interconnections – Western, Eastern, and Texas – and analyzed potential heat rate improvements at plants in each interconnection using three analytical approaches. The agency determined that coal-fired units could achieve an average HRI of approximately 6 percent simply by maintaining their best annual average emission rate over the 2001-2012 time period,[66] similar to the conclusions of the 52-Unit Study. However, EPA improperly decided to choose a rolling *two*-year average to determine the CPP's HRI targets. The agency did not select the two-year average because it was more technically sound than a one-year average, but because it generated more "conservative" standard.[67] Furthermore, none of EPA's methodologies for determining HRI opportunities evaluated O&M practices for reducing heat rates that, while feasible, had not yet been widely adopted.

Given that the BSER must achieve the "maximum practicable degree" of control, *Costle*, 657 F.2d at 326, a revised program must include an element of BSER based on O&M improvements at coal-fired units. In particular, each unit should be expected to implement the best O&M practices that will permit it to maintain its lowest rolling annual average emission rate in the 2001-2017 timeframe. Notably, this calculation should *not* control for reduced-load operation. Coal-fired units that were designed to operate in base-load capacity should not be awarded relaxed emission standards in order to allow them to operate as load-following or peaking units or to cycle frequently, which were never their intended operating modes. As discussed below, our expectation under the reduced utilization element of the BSER is that units will curtail their generation on an *annual* basis by running at baseload capacity for part of the year while shutting down in lower-load seasons. This would permit units to achieve superior heat rates while still curtailing their generation.

Together with HRI based on equipment upgrades and fuel pretreatment/selection practices for coal plants, both discussed below, each unit's mandatory emission rate (expressed as CO_2/MWh) would then be multiplied by its adjusted baseline generation (limited by the reduced utilization component of the

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[65] *See* 80 Fed. Reg. at 64,787-95; EPA, *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units - Greenhouse Gas Mitigation Measures* ("*GHG Mitigation Measures TSD*"), Dkt. No ID No. EPA-HQ-OAR-2013-0602-36859, at 2-28 – 2-51 (Aug. 3, 2015).

[66] *Id.* at 2-43, 2-45, 2-49.

[67] *Id*. at 2-50. As the term was used by EPA at the time, a 3 percent HRI estimate would always be more "conservative" than a 4 percent HRI, while a 2 percent HRI reduction would be more "conservative than 3 percent, and so on. Had the agency established 5-year or 10-year rolling annual averages, the HRI targets would be lower and more "conservative" still. Yet EPA is obliged to determine the *best* system, based on the most technically sound analysis, not some lesser system merely because it is more "conservative." Furthermore, because section 111—and the Clean Air Act overall—seeks to protect public health and welfare by reducing air pollution, a "conservative" assumption (properly defined) would be one that produced *more* emissions reduction, not less. *See Massachusetts v. EPA*, 549 U.S. 497, 506 n.27 (2007) (discussing precautionary language in section 202 that is similar to language in section 111(b)(1)(A)). *Cf. Indus. Union Dept., AFL-CIO v. Am. Petroleum Inst.*, 448 U.S. 607, 656 (1980) (plurality opinion) ("[S]o long as they are supported by a body of reputable scientific thought, the Agency is free to use *conservative* assumptions in interpreting the data with respect to carcinogens, *risking error on the side of overprotection rather than underprotection.*") (emphasis added).

BSER) to establish the unit's TPY limit, expressed in tons per year or pounds per operating hour (computed as a rolling annual average).

ii. Emission reductions achieved through technological improvements at each coal-fired unit.

In addition to improved O&M practices, certain equipment upgrades can also achieve HRI at coal-fired units. An inside-the-fenceline BSER must therefore also include an HRI component based on such upgrades. EPA must evaluate the emission reductions achievable through technological improvements, avoiding double counting of alternate technologies that cannot simultaneously be employed. In the supporting material for the final CPP, EPA includes the following list of examples of equipment upgrades that could achieve HRI at coal plants:

- Install intelligent soot blowing system;
- Replace feed water pump steam turbine seals;
- Overhaul high pressure feed water pumps;
- Upgrade main steam turbine seals;
- Upgrade steam turbine internals;
- Install variable frequency drives for motors;
- Retube or expand the condenser;
- Install sorbent injection system to reduce flue gas sulfuric acid to allow lower temperature exhaust gas;
- Upgrade air heater baskets for lower temperature operation;
- Upgrade and repair flue gas desulfurization systems;
- Refurbish the economizer;
- Upgrade ESP components to lower auxiliary power consumption; and
- Improve SCR and FGD system components to lower draft loss.[68]

This list includes only some examples of the key technology improvements that are available. For instance, it omits the installation of onsite renewable energy options to provide auxiliary electric needs at the facility, and of solar arrays to pre-heat feedwater to the boiler. It also omits major capital projects such as turbine blade upgrades. These measures must be included in any analysis EPA makes of potential HRI at coal plants through equipment upgrades.

EPA must take into account a number of important considerations when formulating a component of the BSER based on HRI through equipment upgrades. First, regulated units may have already installed one or more of the technologies listed above, so the resulting HRI from those installations would already have occurred at those units. Thus far, there exists only anecdotal information about the extent to which any of the listed technologies have been employed at each unit. Second, the amount of improvement expected through any particular upgrade is a relatively small percentage of the unit's overall heat rate and may be difficult to measure.

[68] *GHG Mitigation Measures TSD* at 2-11; *see also* 80 Fed. Reg. at 64,790.

In light of these considerations, EPA should establish a “basket” of technological improvements that would improve coal plant heat rates and lower emissions. This basket should reflect the maximum HRI that can be achieved at regulated units. The agency would establish a “nominal” HRI goal for each of the technologies included in the basket, and as well as an emission target in its guideline document that reflects the sum total of the individual HRI goals for each of the basket’s technologies. If certain equipment required replacement at regular intervals (for instance, every five years) as opposed to one-time installations, the agency would account for this as it calculated the basket’s HRI target over time. If a particular source is mathematically unable to meet its projected HRI target because it has already implemented many of the technologies included in the basket, it can make an appeal in its engineering analysis for a relaxed HRI target. If the state authority were to agree that the unit’s target HRI were not feasible for that unit, it could establish a lesser HRI standard and thus adjust both the unit’s mandatory emission rate target and its annual TPY limit (discussed in more detail below).

Unfortunately, CEMS systems to monitor end-of-stack CO_2 emissions are only accurate within a margin of +/- five percent. Accordingly, any HRI within that bandwidth could effectively be erased through equipment calibration. Based solely on CEMS measures, it is impracticable to ensure that the HRI component of any BSER is actually achieving emission reductions. Accordingly, to ensure that the HRI component of BSER is not being “calibrated away,” EPA must establish compliance demonstration requirements under which sources must submit not only to continuous flow and CO_2 concentration monitoring at regulated units, but also to annual pre- and post-upgrade reference method testing and RATA testing. These requirements would both determine whether the source had satisfied its mandatory emission rate achieved through equipment upgrades and demonstrate the ongoing performance (and proper maintenance) of the installed equipment. The requirements would also ensure that sources do not achieve “false compliance” with their mandatory emission rates by merely recalibrating their flow or CO_2 monitors or installing but failing to maintain new technology.

iii. Emission reductions achieved through fuel pretreatment and selection at each coal-fired unit.

Many operators of coal-fired power plants do not currently apply fuel pretreatment and selection methods to reduce CO_2 emissions from the coal they are firing. For example, sources can reduce their emissions of CO_2 per unit of heat content (lbs CO_2/MMBtu) by drying lignite using waste heat or renewable energy prior to firing it, employing coal beneficiation processes to remove mineral impurities, and blending some higher-rank coal in with lower-rank coal. In addition to HRI through O&M improvements and equipment upgrades, fuel pretreatment and selection can help reduce a coal plant’s end-of-stack emission rates, and should be an element of the BSER. Thus far, EPA has not attempted to evaluate or quantify the opportunities for emission reductions through fuel pretreatment and selection. It should therefore initiate a broad-based information collection request under section 114 of the Clean Air Act to gather sufficient information on this issue.

Based on information that currently exists, we can estimate the range of emission reductions achievable through fuel pretreatment and selection at coal plants. For example, EIA data indicate that the state-wide average CO_2 emission rate per MMBtu of heat content in coal ranges from 211 to 220 lbs CO_2/MMBtu for lignite (with an average 216 lbs CO_2/MMBtu), from 207 to 214 lbs CO_2/MMBtu for sub-bituminous coal (with an average 212 lbs CO_2/MMBtu), and 202-210 lbs CO_2/MMBtu for bituminous coal (average 205 lbs CO_2/MMBtu).[69] Larger differences exist in the CO_2 emissions rates of coal from individual mines. Based on these figures, blending 214 lbs CO_2/MMBtu coal with 207 lbs CO_2/MMBtu coal on a 90:10 ratio (for example) yields a relatively small improvement in emission rates (0.3 percent), but one that is on a scale with several of the equipment upgrades identified by EPA in its ANPRM. By drying lignite with waste heat or renewable energy, operators can reduce the CO_2 emission rate by 2–3 percent or better;[70] this should therefore be considered an essential component of BSER for lignite-fired units. While lignite drying would ordinarily occur at the regulated facility, using fuel that has been dried offsite (like using emission control equipment that has been manufactured offsite) is nonetheless a measure that a facility operator can employ to reduce stack emissions from an individual unit.

iv. Emission reductions achieved through reduced utilization at each regulated coal-fired unit.

a. Reduced utilization is a necessary component of the BSER because HRI and fuel pretreatment/selection standing alone will make only a small difference in coal plant CO_2 emissions and will not produce the maximum feasible reductions.

Under the program we describe in these comments, the majority of emission reductions at coal-fired units would come from curtailing generation at each regulated unit. While the three BSER elements described above will reduce sources' end-of-stack emission rates of CO_2 on a per-megawatt-hour basis, those reductions will be nowhere near sufficient to fulfill this sector's obligation to reduce greenhouse gas emissions as much as feasible. If EPA were to determine that the kinds of measures we have described above are the only acceptable components of the BSER, regulated sources will be required to do only very little (and at some sources, nothing) to reduce CO_2 emissions.

To illustrate this point, consider a rule wherein EPA assumes that the nation's generation mix remains constant through 2030, based on 2012 data. Suppose the rule established an overly lax HRI standard at coal plants of 2 percent (which approximately reflects the lenient Building Block 1 assumptions included in the CPP for much of the country, *see* 80 Fed. Reg. at 64,790), while requiring no additional actions at natural gas-fired plants, consistent with the agency's decision in the Clean Power Plan not to include a building block based on HRI at gas-fired turbines. Under this scenario, overall CO_2 emissions from regulated units would be reduced by merely 1.5 percent over the next 12 years, declining by 33 million tons per year relative to a 2.2 billion ton base.[71] Growth in generation from new gas-fired units not covered under the program, from existing gas-fired units and, indeed, from existing coal-fired units could result in a situation where an HRI-only rule, standing alone, would drive no incremental emission reductions at all. Of course, our analysis in Sections III.A.i-iii indicates that HRI of 6 to 10 percent is readily achievable (and appropriate) to expect at coal plants; we use a 2 percent figure here to reflect the HRI assumptions EPA has made thus far and seems inclined to take in the future.

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[69] EIA, *Carbon Dioxide Emission Factors for Coal*, https://www.eia.gov/coal/production/quarterly/co2_article/co2.html (last visited Feb. 25, 2018).
[70] Levy, E. ,et al., Use of Coal Drying to Reduce Water Consumed in Pulverized Coal Power Plants: Final Report, 3, 8, 47, 86 (Mar. 2006), *available at* https://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/41729-Final.pdf.
[71] *See* EIA, *supra* n. 52, at 111, 187.

In reality, coal-fired generation will *not* remain constant over time. Current trends suggest that coal-fired electric generation is following gas lights and horse-drawn buggies into the history books. The coal fleet is aging considerably; as shown in the table below, over two-thirds of the nation's coal generating capacity was placed in service prior to 1981. Many units are rapidly approaching the end of their useful lives, both from an engineering and a financial perspective. With the retirement of aging units continuing apace, the emission reductions that would occur as a result of the three steps identified above diminish as well.

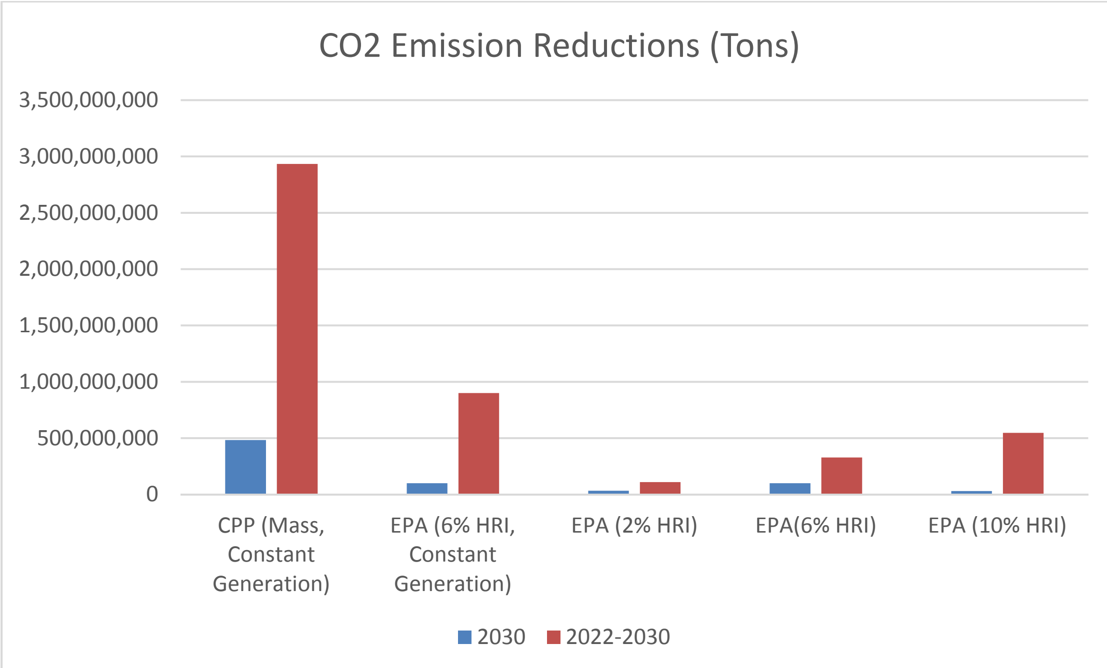
Table No. 1 - U.S. Coal-fired Generating Capacity by In-Service Date

Year of entry into service	Capacity (MW)	Percent of total coal capacity
All units	283,273	100
Prior to 1981	191,389	67.6
Prior to 1980	176,885	62.4
Prior to 1975	124,378	43.9
Prior to 1970	68,070	24.0
Prior to 1965	36,015	12.7
Prior to 1960	20,754	7.3

In fact, in the years since EPA conducted its CPP analysis, coal-fired EGUs have retired at a pace that, if sustained, will result in the closure of two-thirds of the existing coal-fired capacity by 2030. If this trend were to continue, a 2 percent "HRI-only" rule for remaining coal plants would reduce those sources' emissions by only 6 million tons per year – a reduction of just 0.3 percent.

In the following chart, the first two columns illustrate the emission reductions achieved at regulated units by the CPP's existing source-only mass-based compliance option (the "CPP Mass" entry) and a 6 percent HRI-only rule for coal plants, assuming that generation from coal-fired units would remain constant but for the applicable rule. The third through fifth columns illustrate the reductions achieved under a rule that reflects differing levels of HRI stringency assuming that a market-driven reduction in coal generation continues decline as it has from 2012-2017. In light of the limited opportunities for HRI at gas-fired plants, the four "EPA" entries assume that any emission reductions will come entirely at coal-fired units. In each of the four "EPA" entries, the emission reductions represented in the graphs reflect only those that occur as a direct result of an EPA rule, rather than from retirements.

Chart No. 2 - CO_2 Emission Reductions, CPP vs. HRI-Only[72] Rule[73]



On the other hand, it is impossible to predict with accuracy the fluctuations in the generation mix over the next two decades. The current trends in the electric sector may not continue: a number of economists have predicted that the current price advantage held by natural gas will not hold over time and that generation from existing coal-fired EGUs may increase over current levels. The Brattle Group has observed that the rate of "voluntary" coal plant retirements is highly dependent on future natural gas prices, which are impossible to predict with accuracy.[74] Moreover, plant operators and state regulators are unlikely to assign a probability of any given power plant retiring by a certain date until a final determination is made to retire the unit. If coal-fired generation were to increase during the compliance period, this effect could entirely offset the emission reductions achieved through an HRI-only rule.

Earlier projections of a 30-year life for coal-fired EGUs have been revised upward several times, and EPA itself in its IPM runs for the CPP predicts that coal-fired generation in 2030 would increase by 8 percent over 2016 levels in the absence of that rule. These IPM runs do not account for any increase in coal-fired generation that could result from improved efficiency (and hence competitiveness) of coal plants. This phenomenon (sometimes known as the "rebound" effect) together with higher natural gas prices could result in a net increase in CO_2 emissions from the electric sector relative to current emissions, even if

[72] For the sake of simplicity, we are using the term "HRI-only" to refer to a plan that incorporates the three categories of measures discussed previously in these comments (HRI through O&M improvements, HRI through equipment upgrades, and fuel pretreatment/selection of coal), even though fuel pretreatment and selection of coal does not technically affect a unit's heat rate, since it doesn't improve the unit's ability to convert heat content in fuel into electricity.
[73] This table is based on data from EIA, *supra* n. 52, and analyses from the CPP rulemaking.
[74] Aydin, et al., The Brattle Group, *Coal Plant Retirements Feedback Effects on Wholesale Electricity Prices* (Nov. 2013); Celebi, et al., The Brattle Group, *Potential Coal Plant Retirements: 2012 Update.*

EPA were to issue an emission guideline based on relatively aggressive HRI targets. Data also show that retiring coal units tend to be older and less efficient than the fleetwide average. Accordingly, if overall coal-fired generation declines over time by way of retirements, it is likely that the remaining coal units will be among the more efficient EGUs in the fleet. Under this scenario, the existing (and more efficient) fleet may be incentivized to generate more frequently (and emit more CO_2) in order to pick up some of the slack left by the retiring plants.

At best, an HRI-only rule would drive incremental emission reductions that are far too small to meet the legal standard; if coal plant retirements were to continue at a rapid pace, the single-digit emission rate improvements would apply to fewer and fewer units, resulting in smaller and smaller emission reductions. Alternatively, if the coal fleet were to end up *increasing* its generation in the future due to a change in energy markets, the rule might provide incremental benefits compared to a scenario without *any* rule in place, but those benefits would be counteracted by increased generation from coal-fired units. Under this scenario, CO_2 emissions from regulated units would likely *surpass* current levels. At worst, an HRI-only rule could itself drive additional emissions at certain units by enhancing their competitiveness and incentivizing their increased operation. None of these scenarios would satisfy the statutory requirement that a section 111 rule "reduc[e] emissions as much as practicable." *Costle*, 657 F.2d at 326.

These scenarios, however, are far from inevitable. EPA must address *both* the likely continuation of today's trend in coal retirements as well as the extremely harmful effects of a potential "coal rebound." It can do so by adopting a fourth element as part of its BSER determination: reduced utilization at each affected facility. This measure is a legally sound element of BSER, as discussed above, and can be implemented entirely within the four walls of each regulated unit. Below, we provide some suggestions as to how EPA might design a BSER element based on reduced utilization of regulated EGUs.

b. Designing a BSER Component Based on Reduced Utilization of Affected EGUs

i. Curtailment of Coal-Fired Units

There are a number of potential approaches for structuring an emission reduction measure based on reduced utilization of existing coal-fired units; most of these account for each unit's age or a combination of its age and efficiency.[75] As a general matter, older units tend to be less efficient and operate less frequently. By definition, less efficient units use more fuel to generate the same amount of electricity, thus producing higher CO_2 emissions. If such units exhibit declining capacity factors due to part-load or intermittent operation, it is well documented that those units' CO_2 emission rates will increase even further. The table below reflects the correlation between coal unit age and utilization.

[75] For example, in Canada, coal-fired EGUs must meet certain efficiency standards or else retire upon reaching 50 years of age. This will result in the closure of 12 of Alberta's 16 coal-fired units by 2030. Alberta Government, *Phasing out coal pollution*, https://www.alberta.ca/climate-coal-electricity.aspx (last visited Feb. 25, 2018). In addition, China has taken aggressive steps in recent years to retire many of its older and less efficient coal-fired units and to establish stringent efficiency standards for the remaining fleet. Katie Fehrenbacher, *China's Coal Fleet Will Soon Be More Efficient Than America's*, GreenTech Media (May 22, 2017), https://www.greentechmedia.com/articles/read/chinas-coal-fleet-will-soon-be-more-efficient-than-americas#gs.E7o=s2M (last visited Feb. 25, 2018).

Table No. 2- Age of U.S. Coal-Fired EGUs as of 2025 vs. Generation in 2012

Unit Age (years) in 2025	Capacity (GW)	2012 Generation (GWh)	2012 Capacity Factor
<20	8.3	52,954	.75
20-30	3.9	25,204	.69
30-40	22.4	138,247	.70
40-50	99.7	637,786	.73
50-60	102.2	530,063	.59
60-70	39.9	164,032	.47
>70	15.5	64,312	.47

While the correlation between unit age, operational frequency, and efficiency is clear, it is important to recognize that age is not the *only* factor determining a unit's efficiency or operational practices. Some older units are more efficient, and operate more frequently, than many newer units. Nevertheless, age is a helpful indicator of efficiency and operating practices and should be an important factor in determining how to structure a reduced utilization component of the BSER. Furthermore, in addition to age and efficiency, EPA should also consider establishing greater curtailment targets for units that emit air pollution that harms overburdened communities

To apply a reduced utilization element of the BSER, EPA should first identify the amount of overall curtailment of coal-fuel fired units that is achievable while "tak[ing] into account . . . energy requirements," per section 111(a). Second, EPA should apportion curtailment among coal units according to a combination of each unit's age and efficiency, with older and/or less efficient units subject to greater curtailment expectations.

As an initial matter, to derive targets for reduced utilization of regulated coal units, EPA should conduct analysis at the level of each independent system operator ("ISO") in the country. For plants located in sections of the country that are not covered by an ISO, the analysis would be at the level of the individual state in which each plant is located, which serves the same function of ISOs in such instances.[76] Throughout these comments, references to ISOs include individual states serving in ISO capacities.

The agency should start by considering reasonable, objectively supported projections on an ISO-by-ISO basis for each of the following data points:

1. Overall electricity demand growth in the ISO, negative or positive, for each year of the program;
2. The characteristics of the existing fossil fuel-fired fleet, reflected in unit-by-unit inventories for the most recent available year;
3. Announced retirements of existing regulated fossil units, including coal, oil and gas plants;

[76] *See* EIA, *The Electricity Market Module of the National Energy Modeling System: Model* Documentation 2014, at 5 (Aug. 2014), *available at* https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/m068(2014).pdf.

4. Any coal units that are still under construction at the time of proposal (and thus subject to the rule);
5. Any near-term coal units that have been permitted and approved but have not yet started operating;
6. Existing and permitted renewable energy ("RE") resources and energy efficiency ("EE") projects; and
7. The amount of new RE/EE growth that is achievable within the ISO for projected out-years.

Together, these data points will provide EPA with an understanding of the electricity needs of each ISO, the likely make-up of each ISO's fleet of coal-fired units during the program's compliance period, and the extent to which existing and new EE and RE within each ISO can fully meet any load gaps that would result from curtailed generation at regulated coal units. This program would not require EE and RE operators to generate electricity or build new units, nor would it require affected sources to procure credits from RE and EE operators or otherwise guarantee that they generate any particular amount of electricity. Rather, the amount of new RE and EE generation that is achievable in each balancing area—including generation from new installations and increased generation from existing RE and EE—will determine the *extent* to which coal-fired units are expected to curtail their generation under a BSER component based on reduced utilization. When regulated coal units are limited to generate no more than the amount corresponding with their annual TPY limits, other available resources—namely, RE and EE resources, and in some cases, NGCC units—will supply the lost generation due to coal unit curtailments.

The agency would calculate the coal fleet's curtailed generation expectations based on the amount of additional generation that could be provided by existing and achievable EE and RE, taking into account projected coal retirements, as well as any under-construction and near-term coal units that were not yet generating when the updated data inventories were compiled. However, some ISOs have little or no coal-fired generation. In these areas, natural gas-fired units will bear most or all of the reduced utilization corresponding to the amount of achievable RE and EE within the ISO. We discuss curtailment options for natural gas-fired units (both simple cycle combustion turbines ("CTs"), and natural gas combined-cycle units ("NGCCs")) in Section III.B below. In addition, in states with significant amounts of both existing coal and existing gas capacity, EPA may consider establishing a fleetwide ceiling for coal plants that limits the amount of reduced utilization that will occur at these units. To the extent that this ceiling is reached and the ISO still has additional EE and RE capacity to facilitate further generation curtailment at fossil plants, those curtailment expectations would then fall on natural gas-fired units within the ISO. If EPA does choose to establish such a ceiling in a given ISO, that ceiling must be sufficiently stringent to ensure that coal plants achieve the greatest emission reductions feasible.

In ISOs with significant amounts of both existing coal-fired capacity and existing (but underutilized) NGCC capacity, EPA should also further increase coal units' curtailment targets based on the premise that these underutilized NGCC plants could meet further demand gaps resulting from reduced coal generation. However, certain limitations apply; as existing coal plants retire, some portion of the generation from those units would likely be replaced by generation from existing NGCC units. This would leave the latter category of sources with less available capacity to supply replacement generation for curtailed (but not retired) coal units. Furthermore, existing gas units will be subject to their own emission reduction obligations under the rule, which will limit how much these units can operate. EPA must take these factors into account when ascertaining how much additional curtailment should be required at coal units based on the availability of replacement generation from NGCC units.

After determining the overall *amount* of reduced utilization expected for each ISO's coal-fleet, EPA would then allocate that amount among the individual coal units based a combination of each unit's age (with older plants curtailing more generation) and efficiency (with less efficient units curtailing more generation). EPA could also include additional curtailment expectations for plants in or affecting overburdened communities. The following charts illustrate just one of various approaches EPA might adopt to allocate load curtailment targets among the individual units based on a combination of unit age and efficiency. The first chart illustrates a potential age/efficiency dispatch plot for better-performing units, poorer-performing units, and average units. In this chart, generation from the least efficient units falls to zero at age 68, while more efficient plants continue to generate at some level after that age if the operator so chooses. The second chart translates the data from the first chart into maximum annual ton limits for each class of units (i.e., TPY limits) as a declining function of age.

Chart No. 3 –Reduced Utilization Targets for Coal Units Based on Age and Efficiency

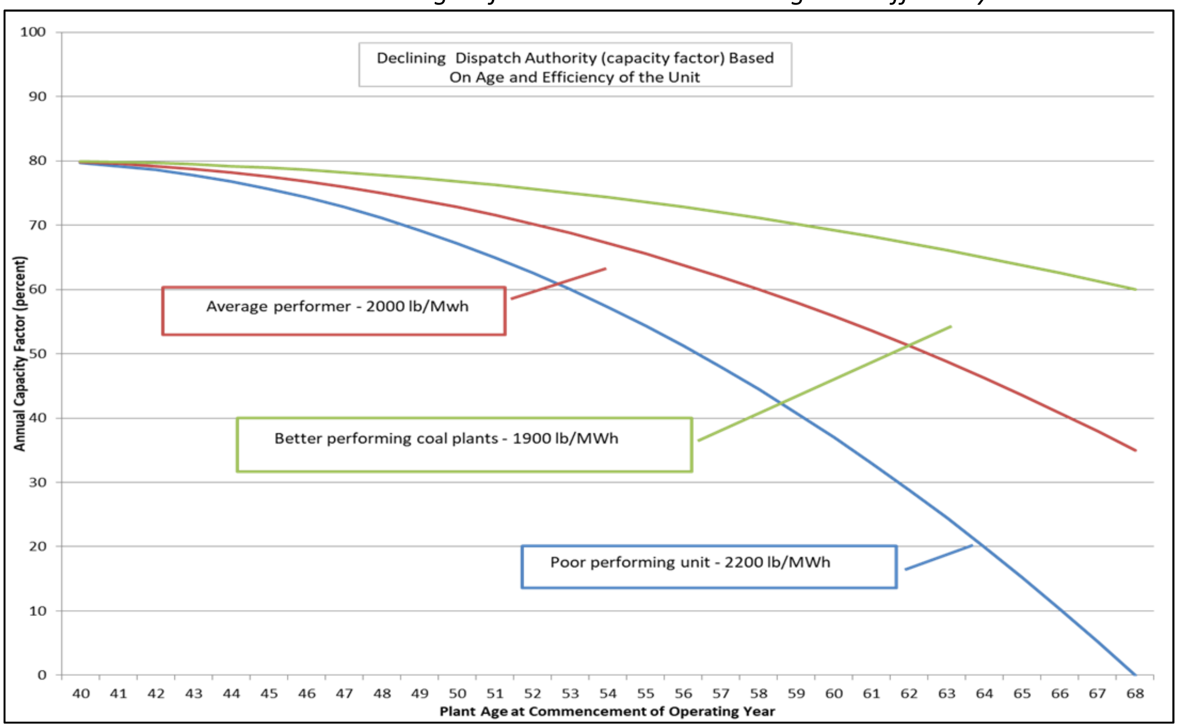
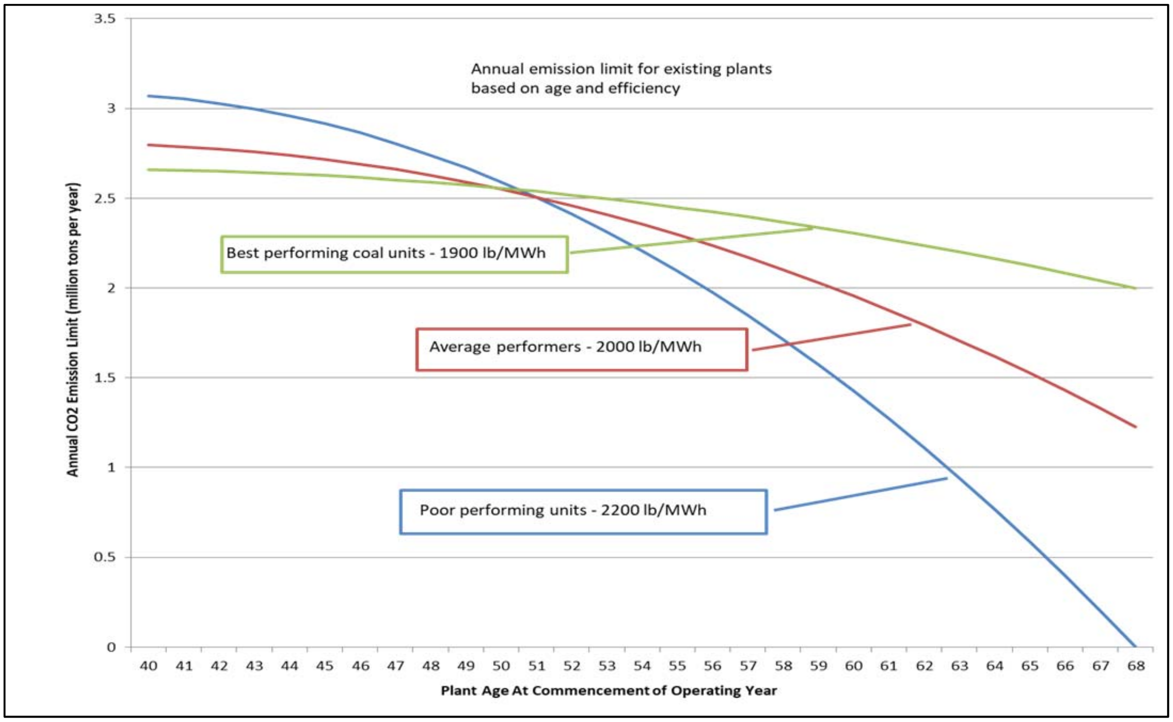


Chart No. 4– CO_2 TPY limits for Regulated Coal Units Based on Age and Efficiency



To calculate a unit's TPY limit, the agency would multiply the unit's enforceable CO_2 emission rate, calculated according to the first three BSER elements described above, by an annual baseline capacity factor, adjusted according to its allocation of the fleet's reduced utilization targets as described above. Because the adjusted capacity factor would be annual, units would not be obligated to run at reduced load or to cycle frequently to reduce their utilization; rather, they could operate at full load for part of the year (during high-load seasons, for instance) and to remain idle for the rest of the year (during low-load seasons). As an alternative to annual TPY limits, EPA could establish for each regulated unit an average lbs CO_2/hr emission rate to be measured on a rolling annual average basis.

Once EPA issues an emission guideline that includes an annual TPY limit (or rolling annual average lbs CO_2/hr emission limit) for each regulated source, it would be incumbent on states to translate those emission limits into enforceable performance standards for the sources within their borders. A state could choose to leave the guideline's emission limits the same and convert them into identical performance standards for each source. Or, a state could formulate a different allocation of emission reduction obligations for the sources in its state, provided that the sum total of emission reductions from all regulated sources within its borders remained the same. If a state were to diverge from the source-by-source TPY limits in the guideline document and devise a new allocation scheme, however, the agency would only approve the plan if the new allocation did not violate critical environmental justice principles. In particular, EPA must ensure that regulated sources whose emissions adversely affect communities of color and low-income communities do not increase their emissions, but actually decrease them. Furthermore, once the agency approved a state plan, the performance standards included therein would reflect hard emission limits for each source; no trading of credits or allowances would be permitted.

As noted above, EPA's program would not impose any legal obligation on *any* entity, be it a state, a regulated source, or an RE/EE resource owner, to provide or procure the RE/EE generation needed to fill in any gaps in demand that might result from reduced utilization of regulated fossil units. Rather, EPA would calculate the amount of potential replacement generation that electricity markets could supply in order to gauge how much reduced utilization to expect at regulated fossil units. However, in order to encourage *lower-emitting* replacement generation (in particular, EE and RE, rather new gas-fired generation), the agency's calculations of potential EE and RE growth in each ISO would be cumulative. In other words, if RE/EE growth in an ISO falls short of EPA's determination of the area's technical potential for such growth in a given year, the following year's RE/EE projections will *increase* to cover the previous year's shortfall, thus resulting in greater curtailment expectations from the fossil fleet. Thus, if an area has unmet potential for RE/EE growth in a given year, that potential will be factored into subsequent years' curtailment assumptions. As we discuss in Section III.C below, EPA can also employ a "netting" approach to address "leakage," which occurs where increased generation from new fossil units not covered under the program partially offsets the emission reductions achieved at existing units that *are* covered under the program.

Moreover, to maintain program effectiveness, EPA should undertake an annual "true-up" procedure to revisit its assumptions regarding electricity demand, coal unit retirements, and the technical potential for RE/EE growth in each balancing area. If the true-up were to reveal disparities between EPA's projections and actual outcomes, the agency would revise and re-allocate the TPY limits for an affected compliance year 24 months prior to January 1 of that year. Furthermore, during the annual true-up process, EPA could adjust the guidelines in response to any unexpected risks to grid reliability.[77]

ii. An illustrative example of BSER application

The following exercise walks through the process EPA would use to calculate a source's TPY limit for a given year. The illustrative unit is a 52-year-old coal-fired EGU. In the baseline year, this unit generated 4 million MWh of electricity (net) at a rate of 2,200 lbs CO_2/MWh (net), emitting 4.4 million tons of CO_2. EPA's BSER assumes that the unit can achieve 4 percent HRI through equipment upgrades and 6 percent HRI thorough improved operation and maintenance practices (as reflected by the unit's 95th percentile lowest rolling annual average emission rate of 2,068 lbs CO_2/MWh (net)). It can further reduce its emission rate by .25 percent through fuel pretreatment/selection of coal. Accordingly, the unit's total emission rate reduction is 10.25 percent, generating an output-based rate of 1,995 lbs CO_2/MWh (net) (2,200*0.8975), or 0.9872 tons CO_2/MWh. This would reflect the source's mandatory lbs CO_2/MWh emission rate, which the governing state would translate into an enforceable performance standard.

With regard to the fourth and final element of BSER—reduced utilization—the source's curtailment target for the year could be easily determined based on a curtailment table reflecting a combination of age and efficiency, as described above. Depicted below is an example of how such table might look; the listed figures represent a percent reduction in annual generation from the unit's baseline. The numbers in the table are merely illustrative. EPA's actual numbers would be different; they would represent

[77] To the extent that grid reliability issues amount to emergencies, the Department of Energy can address these situations under section 215A of the Federal Power Act. That provision gives the Department authority to issue emergency orders for continued operation of "critical energy infrastructure," even if that operation violates Federal environmental statutes, and to exempt utilities responding to those orders from liability for those violations. 16 U.S.C. §§ 824a(c), 824o-1(b), (f)(2); 10 C.F.R. § 205.390.

logarithmic (rather than linear) curves and would be calibrated to ensure that the curtailment of fossil-fired generation overall is equivalent to the projected achievable EE/RE generation figure.

Table 3 - Notional Design of a Curtailment Lookup Table for a Hypothetical Compliance Year (Reflecting Generation Reduction Percentage Relative to Baseline Generation)

BSER-Adjusted Emission Rate (lbs CO_2/MWh)	AGE 50	51	52	53	54	55	56	57	58	59
1800	4.00%	4.40%	4.84%	5.32%	5.86%	6.44%	7.09%	7.79%	8.57%	9.43%
1810	4.20%	4.62%	5.08%	5.59%	6.15%	6.76%	7.44%	8.18%	9.00%	9.90%
1820	4.41%	4.85%	5.34%	5.87%	6.46%	7.10%	7.81%	8.59%	9.45%	10.40%
1830	4.63%	5.09%	5.60%	6.16%	6.78%	7.46%	8.20%	9.02%	9.93%	10.92%
1840	4.86%	5.35%	5.88%	6.47%	7.12%	7.83%	8.61%	9.47%	10.42%	11.46%
1850	5.11%	5.62%	6.18%	6.79%	7.47%	8.22%	9.04%	9.95%	10.94%	12.04%
1860	5.36%	5.90%	6.49%	7.13%	7.85%	8.63%	9.50%	10.45%	11.49%	12.64%
1870	5.63%	6.19%	6.81%	7.49%	8.24%	9.06%	9.97%	10.97%	12.06%	13.27%
1880	5.91%	6.50%	7.15%	7.87%	8.65%	9.52%	10.47%	11.52%	12.67%	13.94%
1890	6.21%	6.83%	7.51%	8.26%	9.09%	9.99%	10.99%	12.09%	13.30%	14.63%
1900	6.52%	7.17%	7.88%	8.67%	9.54%	10.49%	11.54%	12.70%	13.97%	15.36%
1910	6.84%	7.53%	8.28%	9.11%	10.02%	11.02%	12.12%	13.33%	14.67%	16.13%
1920	7.18%	7.90%	8.69%	9.56%	10.52%	11.57%	12.73%	14.00%	15.40%	16.94%
1930	7.54%	8.30%	9.13%	10.04%	11.04%	12.15%	13.36%	14.70%	16.17%	17.79%
1940	7.92%	8.71%	9.58%	10.54%	11.60%	12.75%	14.03%	15.43%	16.98%	18.67%
1950	8.32%	9.15%	10.06%	11.07%	12.18%	13.39%	14.73%	16.20%	17.83%	19.61%
1960	8.73%	9.60%	10.57%	11.62%	12.78%	14.06%	15.47%	17.02%	18.72%	20.59%
1970	9.17%	10.08%	11.09%	12.20%	13.42%	14.77%	16.24%	17.87%	19.65%	21.62%
1980	9.63%	10.59%	11.65%	12.81%	14.09%	15.50%	17.05%	18.76%	20.64%	22.70%
1990	10.11%	11.12%	12.23%	13.45%	14.80%	16.28%	17.91%	19.70%	21.67%	23.83%
2000	10.61%	11.67%	12.84%	14.13%	15.54%	17.09%	18.80%	20.68%	22.75%	25.03%
2010	11.14%	12.26%	13.48%	14.83%	16.32%	17.95%	19.74%	21.72%	23.89%	26.28%
2020	11.70%	12.87%	14.16%	15.57%	17.13%	18.84%	20.73%	22.80%	25.08%	27.59%
2030	12.29%	13.51%	14.87%	16.35%	17.99%	19.79%	21.77%	23.94%	26.34%	28.97%
2040	12.90%	14.19%	15.61%	17.17%	18.89%	20.78%	22.85%	25.14%	27.65%	30.42%
2050	13.55%	14.90%	16.39%	18.03%	19.83%	21.82%	24.00%	26.40%	29.04%	31.94%

The unit would locate the row corresponding to 2,000 lbs CO_2/MWh, the closest to its adjusted baseline emission rate of 1,995 lbs CO_2/MWh (units would be expected to round-up). A 52-year-old unit with an adjusted baseline of 2,000 lbs CO_2/MWh would be expected to reduce its annual generation by 12.84% based on the curtailment table. Since the illustrative unit's baseline generation was 4 million MWh, its BSER-adjusted generation for the compliance year would be 4 million MWh * (1-.1284) = 3,486,400 MWh. Multiplying this generation total by the unit's BSER-adjusted emission rate of 1,995 lbs CO_2/MWh (or .9975 tons CO_2/MWh) yields a TPY limit for the compliance year of 3,477,684 tons, a reduction of 21 percent relative to the baseline year.

B. Emission Limits for Natural-Gas Fired Turbines

As with coal units, the BSER for natural gas-fired combustion turbines—both CTs and NGCCs—would reflect a combination of efficiency improvements and reduced utilization. However, because gas-fired units differ from coal units in both average emission rate and operational function, EPA should create a separate sub-category for gas-fired units. Within this sub-category, EPA would then create an additional layer of subcategories ("secondary groupings") to distinguish gas-fired units by annual hours of operation. These secondary groupings are necessary to reflect the fact that, unlike most coal units, different gas-fired units are designed for different functions: some operate in baseload capacity, some in load-following capacity, and some as peaking units. Emission rates of gas-fired turbines will generally vary significantly based on their operational design specification, necessitating the additional layer of sub-categories. We also recommend a subcategory for small NGCC units of capacity less than 125 MW, which have a higher emission rate on average than larger NGCCs.

While the opportunities for HRI at gas-fired turbines are generally less than at coal plants, EPA must still ensure that the gas plants are operating at the level of efficiency needed to achieve the maximum feasible emission reductions. This would involve the same procedures used to calculate HRI targets at coal plants. First, the agency would examine each regulated unit's historical operating data and calculate its highest 95th percentile rolling annual average emission rate, which the unit would be expected to maintain going forward. Next, EPA would review the available technologies and equipment upgrades that could yield HRI at gas plants and publish a menu of options for technical upgrades. Gas-fired units would then be required achieve a lbs CO_2/MWh emission limit reflecting the greatest HRI achievable through improved O&G and equipment upgrades. As with coal-fired units, gas-fired EGUs would be subject to compliance demonstration requirements to ensure the integrity of the HRI component of the BSER. This would include pre-implementation engineering analyses and pre-and post-implementation reference method testing to demonstrate initial compliance with the technical upgrade component of the BSER, while ongoing CEMS data would show maintenance and operation of these upgrades.

After establishing unit-specific emission rate requirements for each gas plant, EPA would then determine an appropriate level of reduced utilization for sources in this sub-category. As noted above, in gas-heavy ISOs, such as California ISO, natural gas units will bear most or all of the burden of curtailing their generation to an extent that corresponds to the capacity for RE and EE to provide replacement generation. In states with a mixture of coal and gas capacity, the agency may apportion reduced utilization targets to both the coal and gas fleets in a way that ensures the greatest emission reductions feasible are achieved (*see* Section III.A.iv.b above discussing ISO-specific ceilings on reduced utilization at coal plants). And in ISOs with relatively little gas-fired generation, coal units will bear the greater share of reduced utilization. In these areas, with the curtailment targets for NGCCs would eventually reflect a limitation on the amount of increased generation those units could produce.

To determine unit-by-unit curtailment targets at gas plants, EPA would once again take into account plants' age and efficiency. However, EPA must respond to several important considerations specific to the gas fleet. For instance, the gas fleet's curtailment curves should ensure that units with emission rates greater than 1,050 lbs CO_2/MWh (i.e., peaking units) would, over time, reduce their utilization to a level corresponding to an 8 percent rolling annual capacity factor at full-load. This would reduce and ultimately eliminate the environmentally damaging practice in which the least efficient peaking units operate in load-following or baseload applications. On the other hand, units designed to operate in baseload capacity that do so operate would be subject to lower curtailment targets compared to less efficient units. Also, unlike coal plants, gas-fired units are equipped with duct burners; curtailment of these devices would be treated in the same manner as curtailment of simple-cycle turbines. At some point in coal-heavy states, curtailment of NGCCs would reflect a limit on the amount of *increase* that such units could experience. Under this approach, curtailment reflective of projected available RE/EE not used in the coal curtailment calculation would lead to an outcome where generation by the most efficient NGCC units in ISOs with significant coal generation would not likely be reduced.

Once EPA has determined the HRI and generation curtailment expectations at each gas unit in the country, it would include those unit-specific emission limits in its guideline document reflecting each unit's maximum lbs CO_2/MWh emission rate and its TPY limit. As with coal plants, each state would then be responsible for issuing performance standards for the gas-fired units within its borders.

C. General Technical Comments

In developing a program based on the discussion provided above, EPA must consider the following general technical considerations:

- **EPA must compile an updated plant-by-plant inventory.** The CPP is based on conditions that existed in 2012 and earlier. Much has changed in the electric sector since that time. Several hundred coal-fired EGUs have retired in the interim, and the remaining coal fleet is operating at reduced utilization vis-à-vis 2012. For specific data on recent changes in the sector, *see* Section II.A above. These trends are continuing, and must be reflected in any new rulemaking. The agency must compile an updated plant-by-plant inventory based on the most recent year available, and must also provide commenters with this information in a timely manner so that they can fully evaluate the effects of whatever proposal EPA may issue. Furthermore, EPA has now had several years to acquire and evaluate data for units in Alaska and Hawaii and those in Indian country, and should collect data on these sources and regulate them in any new rule.

- **Issue an information collection request for unit-specific information.** Industry comments and technical articles provide information about potential upgrades that would reduce emissions at fossil-units that is often anecdotal and self-selecting in terms of which units they describe. EPA should issue a mandatory information collection request under section 114 of the Clean Air Act to ascertain the extent to which potentially available technological upgrades have actually been implemented at existing units, as well as the efficiency improvements these upgrades achieved.

- **Update RE and EE assumptions.** In the CPP, EPA based its projections of future RE installations on the average installation rate over the 5 years prior to 2012. As noted above, RE growth since those years (particularly among solar generators) has been substantially greater than in the 2007-2012 period. The agency should therefore revise the CPP's Building Block 3 assumptions regarding potential RE growth to reflect this change, which would significantly strengthen the program. The agency should also conduct a new survey of unrealized EE opportunities and should revisit its assumptions about how much RE displaces coal rather than gas.

- **Address "leakage."** In the CPP, the concept of "leakage" was described as the possibility that regulated entities operating in mass-based states might comply with the rule by shifting generation from existing fossil units (subject to the CPP) to newly constructed gas units (not subject to the CPP), which could significantly erode the efficacy of the rule and would result in fewer real-world emission reductions than would otherwise occur. 80 Fed. Reg. at 64,822. The CPP attempted to address this concern by requiring states choosing mass-based compliance approaches to demonstrate equivalence between their state plans and the results that would occur under a corresponding rate-based program, and to include measures in their plans to ensure that such equivalence would be maintained. The program described in these comments includes both a lbs CO_2/MWh emission rate requirement—for which leakage would not be a concern—and a tons CO_2/year emission limit—for which leakage would need to be addressed.

One potential option that EPA should consider to preserve the integrity of the program's TPY limits is a "netting" concept. Under this approach, the TPY limit for each regulated fossil unit is adjusted each year according to the characteristics of the replacement generation that has emerged in that ISO in the previous year. Under this approach, the existing fossil units' TPY limits would be reduced (i.e., made more stringent) by a given amount for each new MWh of generation from new fossil fuel-fired units that is added in the balancing area in lieu of projected RE/EE generation. Where the balancing area meets the level of projected RE/EE for that year, no adjustment of the existing fleet's TPY limits would occur.

An example illustrates how this might work. Assume that in Year X, a 400 MW NGCC in a particular balancing area retires and is replaced by an identical unit with the same emission rate, while the total amount of RE/EE generation in the balance area remains constant in Year X relative to the previous year. Under this circumstance, the TPY limits for each regulated unit remaining in the balancing area would be reduced for Year X+1 below the original targets in order to reflect the fact that the area did not reach its maximum capacity in Year X for supplying replacement generation from RE/EE, but instead replaced retiring generation with new fossil capacity.

Under this scheme, the allocation of additional generation curtailment targets to remaining units would be proportional to the new fossil unit's share of the CO_2 emissions (in tons). Thus, construction of a new higher-emitting simple-cycle CT would require greater increases in curtailment targets at remaining units than would the construction of a lower-emitting combined-cycle NGCC. And, as noted above, allocation of additional curtailment expectations would also be proportional to the RE and EE growth in the ISO for a given year. If RE and EE growth were to fully meet EPA's projections in the ISO for that year, there would be no adjustments to the remaining units' curtailment expectations for the following year.

There are a variety of ways in which EPA could design a netting method to deal with leakage; the description above simply represents one possible approach. One advantage of a netting method along these lines is that it would not result in the "regulation" of newly constructed units under section 111(d); while generation from new fossil units would affect the obligations of existing units, those new sources would have no legal obligations of their own under this program.

- **A note on trading.** Based on the language in the ANPRM, it appears that the Administrator now interprets section 111 to prohibit the BESR from including or otherwise taking into account any mechanism based on trading of emission allowances or emission reduction credits. Yet if such measures could nonetheless be used for compliance purposes, the result would be unlawful and arbitrary. There is simply no rational basis for establishing a trading regime that would ease sources' compliance obligations while failing to set emission limits at a level that reflected that regime. The program we describe in these comments does not include a trading mechanism in either the BSER nor among its compliance options. EPA must also adhere to this principle in any emission guideline it issues for power plant CO_2 emissions that does not account for trading in its target-setting exercise. Otherwise its program will be unlawful, and will violate the requirement for rational agency decisionmaking.

IV. Responses to Questions Posed in the ANPRM

Are changes to EPA's 111(d) regulations (Subpart B of 40 CFR Part 60) warranted? Section 60.24 of the Implementing Regulations allows the establishment of emission standards based on an allowance system or emission rates. 40 C.F.R. § 60.24(b)(1). As explained elsewhere in these comments, if EPA adopts an interpretation that would preclude the use of allowance mechanisms to determine the emission reduction targets, then states must not be allowed to establish allowance mechanisms for purposes of compliance. Accordingly, EPA must include the following language in any CO_2 emission guidelines that do not include allowances for target-setting purposes: "Notwithstanding any other provision of this title, standards based on this emission guideline shall not be based on an allowance system."

- **Would it be beneficial to States for the EPA to provide sample state plan text as part of the development of emission guidelines?** Yes, subject to notice and comment, if it is to be part of a presumptively approvable plan.

- **What is the role of a State in setting unit-by-unit or broader emission standards for EGUs within its borders, including potential advantages of such an approach and potential challenges?** As a general rule, under the Clean Air Act, states are free to adopt more stringent emission limitations than those required by EPA except where state laws prohibit them from doing so. The potential advantages of more stringent standards are obvious, and we do not envision any challenges that could not be adequately addressed—as indeed they are currently being addressed in the implementation of more stringent programs that exist today.

- **Should EPA adopt an approach in which it determines what systems may constitute BSER without defining presumptive emission limits and then allows the States to set unit-by-unit or broader emission standards based on the identified BSER while considering the unique circumstances of the State and the EGU?** No. We discuss this issue in detail in the joint comments we are concurrently submitting to this docket along with other environmental organizations.

- **Comment on the burden that it would create for States to determine unit-by-unit emission standards for each EGU.** Under the program discussed above, EPA will determine unit-by-unit emission limits for each EGU, and states will translate those emission limits into enforceable performances standards. Alternatively, EPA could develop the appropriate data sets and algorithms so that states can "do the math" and determine unit-by-unit emission standards with little effort. We also note that it would be arbitrary and capricious for EPA to consider only the burdens associated with unit-by-unit standards, without also taking into account the benefits of such an approach.

- **Comment on the burden for determining what the remaining useful life of a given source is and how that should impact the level of the standard.** The term "remaining useful life" has never been defined by statute or regulation, and EPA does not offer a proposed definition in the ANPRM. The design life of fossil fuel-fired steam EGUs is generally considered to be 30 years, while the service life of major components is considered to be somewhat shorter. By this metric, the "remaining useful life" of the vast majority of U.S. EGUs as that term would have been understood when Congress passed the Clean Air Act Amendments of 1977 is zero.

Studies have reported that operators consider a number of factors in deciding whether to retire an existing unit, including the pendency or issuance of new environmental regulations. Indeed, in the absence of such regulations, the environmental harm done by extending the life of old, highly polluting plants is improperly externalized rather than borne by the polluting entities. Thus, at the very least, the term "remaining useful life" must include consideration of applicable environmental regulations.

For the program described in these comments, remaining useful life considerations would be relevant under the following, narrowly defined circumstances: first, for heat-rate improving technological improvements at a unit that is reaching or has reached the end of its useful life when those improvements would entail extraordinarily large capital investments; and, second, when applying the reduced utilization element of the BSER.

In the first case, where an aging plant's HRI target based on technological upgrades includes an extraordinarily large capital investment, the plant's operator may appeal to the state enforcement authority for a relaxation of the HRI target based on section 111(d)'s remaining useful life provision. In any such appeal, the applicant would carry the burden of justifying a relaxation of HRI by demonstrating a limited remaining useful life of its plant and proposing a retirement date. EPA would have to require in its guidelines that any state granting such a request impose an enforceable permit obligation on the source operator to retire the unit by a date certain that assures the plant's continuing emissions will not increase the state's fleet-wide emission targets. Furthermore, to the extent that the state can substitute other technology upgrades to improve the source's HRI that do not involve extraordinarily large capital investments (and that were not already included in that source's HRI target), the state must do so.

In the second case, EPA's application of the reduced utilization element when determining the BSER under this program already takes into account remaining useful life of regulated units when apportioning the amount of overall curtailment among coal units according to each unit's age (and efficiency), with older (and/or less efficient) units subject to greater curtailment expectations. In establishing standards of performance, state agencies would be able to establish TPY limits different than those set forth by EPA in its emission guideline, so long as these old units do not increase their emissions, the overall amount of curtailment identified by EPA for a given state is achieved, and environmental justice considerations are taken into account.

It is important to emphasize that the statutory reference to remaining useful life does not place a thumb on the scale in the direction of *less* protective emission limits. On the contrary, under §111(d)'s plain language, remaining useful life considerations can justify *more* protective limits than would otherwise apply. Here, in the absence of an obligation to install partial carbon capture and sequestration or other large capital expenses, consideration of remaining useful life could well mean *increasing* the curtailment of older, less efficient units compared to newer, more efficient units.

We note that units reaching the end of their useful lives would under no circumstances be exempt from (or subject to relaxed obligations with regard to) other requirements contemplated under this program, such as changes in O&M practices and fuel pretreatment.

- **How can existing state GHG programs interact with, or perhaps, satisfy, a potential rule?** Compliance with one set of requirements may complement the other program, or may proceed on its own track. However, no federal or state GHG programs that currently exist establish an absolute maximum limit (i.e., without the option to acquire allowances) on the amount of CO_2 that each regulated source may emit in a given year. That said, we are unaware of any instance where a unit-by-unit EGU limitation would conflict with state GHG programs or vice-versa. Because the program discussed in these comments would not include allowance trading, it would operate separately from state programs.

- **What additional compliance flexibilities should States be able to employ in developing state plans?** The Administrator's new (and unreasonable) legal theory requires the BSER to include only "measures . . . based on a physical or operational change to a building, structure, facility, or installation at that source." 82 Fed. Reg. at 61,512. As noted above, the ANPRM indicates that this theory would prohibit the incorporation of tradeable credits or allowances in determining the BSER and setting the emission reduction targets. Accordingly, no such flexibilities may be permitted in state plans, either. If EPA does not incorporate a mechanism for trading in its BSER, it must also prohibit states from including such a mechanism in their compliance plans. Any deviation from this principle would be unlawful under the new legal theory EPA described in the CPP repeal and ANRPM, and would reflect irrational–and thus arbitrary—agency decisionmaking. As noted above, the program we describe in these comments does not include trading either in the BSER or as a compliance option.

- **Should States be able to develop plans that allow emissions averaging? If so, should averaging be limited to units within a single facility, to units within a State, to units within an operating company, or beyond the State or company?** Averaging emission limits of units within a facility should only be permitted where EPA has evaluated the additional emission reductions that can be achieved and incorporated those reductions into a facility-wide generation-weighted limit. To the extent that the Administrator asserts that averaging *across* facilities could not be a component of the BSER under its new legal theory of section 111, it must prohibit the use of trading for compliance purposes.

- **If averaging is not limited between units in different States or between units owned by the same company, are any special requirements needed to facilitate such trading?** Once again, if EPA excludes trading from the BSER and from goal-setting, it must also exclude it in state compliance plans as well.

- **Comment on the proper roles of EPA and the states in this process.**
Under the program discussed in these comments, the roles of EPA, the states, ISOs, and the public would remain as they are today. EPA would issue emission guidelines establishing annual TPY limits for each unit, and state environmental agencies would develop and enforce plant-specific performance standards reflecting the guidelines' emission limits. In the early years of the Acid Rain Program, many operators demonstrated compliance by curtailing generation at Phase I units (subject to TPY SO_2 limits) while increasing generation at as-yet unregulated Phase II units. State energy agencies, ratemaking entities, ISOs, and regional transmission

organizations managed the grid even as this "redispatch" occurred, just as they now manage a system that is continually adding and losing generating units and experiencing technically-based curtailments. As they have in the past, ISOs (and states that act as balancing authorities) would continue to conduct capacity auctions, while operators of individual units would bid the capacity that is available to them based on the physical condition of their units and any applicable regulatory constraints. These actions occur early enough so that whatever capacity is bid into the system will be available during the applicable period. These activities are not new and have routinely taken into account unit retirements, new generation (both fossil and renewable), and regulatory constraints, such as the Acid Rain Program's emission reduction requirements and SIPs' ozone season NO_x limits.

States would implement the guidelines by, among other things, issuing enforceable performance standards, incorporating limits in Title V programs, conducting inspections, and serving as first-line government enforcers. State energy regulators would continue their activities as before, but with knowledge of the additional constraints on emissions from the energy system (as they always do whenever EPA issues a pollution control measures for the power sector). States would also address special situations affecting the initial federal consideration of unit age and efficiency, subject to the constraints that any revisions not reduce the efficacy of the guidelines. Where a state declined to participate in the program, EPA would fulfill the state's role in these regards. Because a unit-by-unit approach is straightforward and simple to administer, initial implementation of such a rule could occur in 2020.

The public would have near-real-time, online access to generation data, CEMS monitoring, reference test results and calibration, inspection reports, and other pertinent information relating to sources' obligations under the program. The emission limits and other requirements established under this program would be subject to citizen suit enforcement.

After promulgating the guidelines, EPA (along with DOE) would continue to acquire information needed to evaluate and periodically update them. The initial guidelines would specify the objective basis for annual adjustments of the guidelines' TPY limits for individual units without further rulemaking requirements. EPA should also commit to evaluate the guidelines after three years and revise them as necessary and appropriate every five years.

- **What are the merits/demerits of differentiating between gross and net heat rate?** EPA should use both gross and net heat rate/CO_2 emission rate as appropriate in this process. Operators routinely report "gross load" to EPA's Air Market Program Division ("AMPD") under 40 C.F.R. Part 75 and net generation to DOE and for commercial purposes. Measurement and reporting of net generation is highly regulated and likely more accurate than the gross generation figures in the AMPD. Moreover, net generation is more relevant to the purposes of this rule and would encourage HRI through improved efficiencies in pollution control devices and ancillary equipment such as pumps, conveyors, and the like. However, there may be more "unit-specific" gross generation data available over time and the use of just net generation would disadvantage those units that have pollution controls, such as flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") equipment, in comparison to units that do not.

  EPA can address this issue by generally employing net generation figures (assuming they are available over the long-term) and developing an estimate or set of estimates for the energy impact of various control devices. EPA would then adjust the "efficiency" component of the reduced utilization component of the BSER as described above, such that well-controlled units are not curtailed to a greater extent than similarly performing uncontrolled units. If long-term unit specific performance data are not available to determine opportunities for O&M improvements on a net basis, the gross performance data can be used to estimate the amount of such improvement, and can subsequently be converted to a net rate based on an evaluation of the difference between net and gross rates at each specific unit.

- **What systems of emission reductions options that may be considered as compliance options for individual units even though they may not meet the criteria for consideration as the BSER (because, for example, they may not be broadly applicable)?** Where the BSER is limited to actions that can be applied to or at a stationary source, the compliance obligations must also be limited to those actions that can be applied to or at a stationary source. “Broadly applicable” does not mean “universally applicable,” and under a unit-by-unit approach, EPA should consider whether a particular compliance option is applicable at each unit. If EPA were to exclude available compliance options from consideration in the BSER based on an overly narrow interpretation of “broadly applicable,” the resulting BSER would be unlawful.

- **Should EPA retain its earlier exemptions for simple cycle turbines and CHP units?** No. These classes of units generate millions of tons of CO_2 per year. As discussed above, curtailing generation of simple cycle turbines currently operating in load-following or baseload functions would likely provide the most significant opportunity to reduce emissions from natural- gas fired units.

- **Comment on the interactions between a section 111(d) rule for fossil fuel-fired EGUs and NSR requirements for such units under the Clean Air Act.** Countries that generate most of the non-U.S. coal-fired electricity in the world, including the 28 countries of the European Union, China, India, and South Korea, have adopted existing source emission standards for SO_2 and NO_x. The United States has not adopted such limits for coal-fired EGUs, based on a legislative compromise that dates back 40 years, under which EPA would adopt and update standards for new sources (the NSR and NSPS programs), but existing sources, expected to retire shortly, would be “grandfathered.” This compromise contained an exception to grandfathering: if a unit were modified in such a way that annual emissions increased “significantly,” the unit would have to install modern controls, such as FGD and SCR. There is a patchwork of other requirements that force coal plants to install modern controls, some of which only require seasonal operation of controls. As a consequence, approximately one-third of U.S. coal-fired generation does not employ FGD to control SO_2 and more than half of U.S. coal generation occurs without operation of SCR to limit NO_x. In contrast, Chinese deployment rates for FGD and SCR are at 99 and 92 percent, respectively.

  Having been beneficiaries of the legislative compromises of the 1970s, some operators in the industry and their allies refuse to fulfill their part of the bargain. Notwithstanding that precedent for regulating pollution under the common law and by regulation dates back to the 1600s, these advocates seem to believe are entitled to pollute the commonweal at whatever level best serves their economic interests, and, whenever their allies manage EPA, they press for “NSR Reform” to extend the license of antiquated facilities to operate without modern pollution controls. Here, once again, we see the push for “NSR Reform,” this time under the guise of “energy efficiency” projects needed to address climate change. In the ANPRM, EPA asks “[w]hat other approaches would minimize the impact of the NSR program on the implementation of a performance standard for EGU sources under CAA section 111(d)?" 82 Fed. Reg. at 61,519. We submit that, considering the overall goals of the Clean Air Act, EPA should be asking whether there are specific approaches that will accelerate the retirement of grandfathered units, thus cutting emissions that are causing large numbers of deaths and illnesses in people, as well as large ecosystem harms such as eutrophication and acidification of waterways. *See* 76 Fed. Reg. 48,208, 48,309 (Aug. 8, 2011); 66 Fed. Reg. 5,002, 5,025-26 (Jan. 18, 2001).

The purpose of these regulations is not "efficiency for efficiency's sake." Rather, the purpose of GHG emission regulation is to provide meaningful emission reductions from this sector in order to ameliorate the harm these emissions pose to public health and welfare. Efficiency improvements can be a tool to help achieve that end, but actions that increase the overall emissions from the sector are of no value, even if they improve an individual unit's emission rate in lbs CO_2/MWh.

Operational efficiency improvements, such as optimized sootblowing, neural nets, and O&M improvements would not likely increase projected annual emissions of these units. However, replacement of major components such economizers, heaters, and condensers often increases annual emissions of SO_2, NO_x, PM, and CO_2 by reducing forced outage rates and increases overall emissions from units by extending their lifetimes. Accordingly, life extension projects, which have been adjudged to trigger the Clean Air Act's NSR provisions, must not be favored by any special provision or exemption. In addition, the D.C. Circuit has ruled unlawful EPA's prior attempt to exempt "pollution control projects" from the definition of "modification" under the NSR program. *New York v. EPA*, 413 F.3d 3, 40-42 (D.C. Cir. 2005), *rehearing denied*, 431 F.3d 801 (D.C. Cir. 2005). Any attempt to grant sources an end-run around the NSR requirements in response to section 111 emission standards would thus violate the Clean Air Act.

We are aware of arguments presented by some industry advocates that one type of capital project in particular— turbine blade upgrades—is an efficiency improvement that should be exempt from NSR. EPA must reject such arguments as contrary to the Clean Air Act and case law. Moreover, such arguments make no sense from a policy perspective. First, if an operator is willing to invest the capital sums involved for replacement of all three stages of the turbine blade, there is no policy argument for not upgrading the pollution controls at that time as well. Second, while there are some designs for turbine upgrades that also increase the capacity of the unit and de-bottleneck the boiler, there is no constraint under the Laws of Thermodynamics that suggests that turbine efficiencies cannot be improved while maintaining the original heat input to the unit. And there is nothing that would preclude the operator from obtaining a synthetic minor permit that avoids triggering NSR.

- **Comment on the interactions between a section 111(d) rule for fossil fuel-fired EGUs and the section 111(b) NSPS for such sources.** We can envision situations where some sources might seek to escape the obligation to comply with their unit-specific 111(d) obligations if their compliance obligation under 111(b) were less stringent. If EPA were to adopt a replacement 111(d) rule such as the framework discussed here, it can address this issue by revising the modification provisions in the section 111(b) rule at the same time to specify that the applicable requirement for a modifying source is the more stringent of the two obligations.

Respectfully submitted,

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